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.

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[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 III 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]

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

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 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) × 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).

* * * * *

(m) * * *

(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)

$$E = \frac{1.194 \times 10^{-7} \times (NO_X)_c \times Q_{std}}{P} \quad (Eq. 1)$$

Where:

E = NO_X emission rate, in lb/MWh;

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

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

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

$$E = \frac{1.664 \times 10^{-7} \times (SO_2)_c \times Q_{std}}{P} \quad (Eq. 1)$$

Where:

E = SO_2 emission rate, in lb/MWh;

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

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

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

3.413×10^6 = 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)

$$E = E_{NG} \times \frac{H_{NG}}{H_T} + E_{Non-NG} \times \frac{H_{non-NG}}{H_T} \ (\text{Eq. }8)$$

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
3.413×10^6 = 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)

$$E = \frac{(SO_2)_m}{BL \times AL} \quad \text{(Eq. 4)}$$

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)

$$E = \frac{1.194\times10^{-7} \times (NO_x)_c \times Q_{std}}{P} \quad \text{(Eq. 1)}$$

Where:

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

(2) Measure the NO_X and diluent gas concentrations using either EPA Method 7E in appendix A–4 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;

1.664×10^{-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.

[FR Doc. 2026–00677 Filed 1–14–26; 8:45 am]

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to the public interest.'' *See Nat. Res. Def. Council* v. *Nat'l Highway Traffic Safety Admin.,* 894 F.3d 95, 114 (2nd Cir. 2018) (noting that an agency may invoke the good-cause exception when notice and comment are ''unnecessary'' in ''those situations in which the administrative rule is a routine determination, insignificant in nature and impact, and inconsequential to the industry [ ] and to the public'').

By statute, Congress has authorized an aggregate period of 81 months of assistance to individuals who use Chapter 35 benefits combined with benefits from other programs listed in section 3695(a). VA's authority is limited to implementing the statutes as enacted by Congress. Therefore, additional public comment would be superfluous and unnecessary.

The APA also requires a 30-day delayed effective date, except for ''(1) a substantive rule which grants or recognizes an exemption or relieves a restriction; (2) interpretative rules and statements of policy; or (3) as otherwise provided by the agency for good cause found and published with the rule.'' 5 U.S.C. 553(d). For the reasons stated above, the Secretary finds that there is also good cause for this rule to be effective immediately upon publication. Any delay in implementation would be unnecessary for purposes of 5 U.S.C. 553(d)(3).

Executive Orders 12866, 13563, and 14192

VA examined the impact of this rulemaking as required by Executive Orders 12866 (Sept. 30, 1993) and 13563 (Jan. 18, 2011), which direct agencies to assess all costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits. The Office of Information and Regulatory Affairs has determined that this rulemaking is not a significant regulatory action under Executive Order 12866, as supplemented by Executive Order 13563. This final rule is a deregulatory action under Executive Order 14192. The Regulatory Impact Analysis associated with this rulemaking can be found as a supporting document at *www.regulations.gov.*

Regulatory Flexibility Act

The Regulatory Flexibility Act, 5 U.S.C. 601–612, is not applicable to this rulemaking because notice of proposed rulemaking is not required. 5 U.S.C. 601(2), 603(a), 604(a).

Unfunded Mandates

The Unfunded Mandates Reform Act of 1995 requires, at 2 U.S.C. 1532, that agencies prepare an assessment of anticipated costs and benefits before issuing any rule that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more (adjusted annually for inflation) in any one year. This final rule will have no such effect on State, local, and tribal governments, or on the private sector.

Paperwork Reduction Act

This final rule contains no provisions constituting a collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3521).

Congressional Review Act

Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), the Office of Information and Regulatory Affairs has designated this rule as not a major rule, as defined by 5 U.S.C. 804(2).

List of Subjects in 38 CFR Part 21

Administrative practice and procedure, Armed forces, Civil rights, Claims, Colleges and universities, Conflict of interests, Defense Department, Education, Employment, Grant programs—education, Grant programs—veterans, Health care, Loan programs—education, Loan programs—veterans, Manpower training programs, Reporting and recordkeeping requirements, Schools, Travel and transportation expenses, Veterans, Vocational education, Veteran readiness.

Signing Authority

Douglas A. Collins, Secretary of Veterans Affairs, approved this document on July 24, 2025, and authorized the undersigned to sign and submit the document to the Office of the Federal Register for publication electronically as an official document of the Department of Veterans Affairs.

Taylor N. Mattson,

Alternate Federal Register Liaison Officer, Department of Veterans Affairs.

For the reasons stated in the preamble, VA amends 38 CFR part 21 as set forth below:

PART 21—VETERAN READINESS AND EMPLOYMENT AND EDUCATION

Subpart D—Administration of Educational Assistance Programs

■ 1. The authority citation for part 21, subpart D continues to read as follows:

Authority: 10 U.S.C. 2141 note, ch. 1606; 38 U.S.C. 501(a), chs. 30, 32, 33, 34, 35, 36, and as noted in specific sections.

■ 2. Amend § 21.4020 by:

■ a. In paragraph (a)(4), by removing ''35,'';

■ b. Revising paragraph (a)(5);

■ c. Removing the authority citation following paragraph (a)(8); and

■ d. Adding paragraph (c) before the authority citation at the end of the section.

The revisions and addition read as follows:

§ 21.4020 Two or more programs.

(a) * * *

(5) 10 U.S.C. chapters 107, 1606, 1607, and 1611;

* * * * *

(c) *Limit of Aggregate Assistance.* The aggregate period for which any person may receive assistance under 38 U.S.C. chapter 35 in combination with any of the provisions of law referred to in paragraph (a) of this section may not exceed 81 months (or the part-time equivalent thereof).

* * * * *

[FR Doc. 2025–14486 Filed 7–30–25; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2025–0162; FRL–12675–01–OAR]

RIN 2060–AW61

Extension of Deadlines in Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Final Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Interim final rule; request for comments.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is taking interim final action to extend certain deadlines within the final rule titled ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,'' 89 FR 16820 (March 8, 2024) (hereafter ''2024 final rule''). Specifically, the EPA is extending deadlines for certain provisions related to control devices, equipment leaks, storage vessels, process controllers, and covers/closed vent systems in ''Subpart

OOOOb—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022'' (NSPS OOOOb). The EPA also is extending the date for future implementation of the SuperEmitter Program. Finally, the EPA is extending the state plan submittal deadline in ''Subpart OOOOc—Emissions Guidelines (EG) for Greenhouse Gas Emissions From Existing Crude Oil and Natural Gas Facilities'' (EG OOOOc). The EPA is requesting comments on all aspects of this interim final rule and will consider all comments received in determining whether amendments to this rule are appropriate after the conclusion of the comment period.

DATES: This interim final rule is effective on July 31, 2025. Comments on this interim final rule must be received on or before September 2, 2025.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2025–0162, by any of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2025–0162 in the subject line of the message.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPAHQ–OAR–2025–0162, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m.–4:30 p.m., Monday–Friday (except Federal Holidays). Comments received may be posted without change to *https://www.regulations.gov,* including any personal information provided. For detailed instructions on sending comments, see the ''Public Participation'' heading of the General Information section of this document.

FOR FURTHER INFORMATION CONTACT: Amy Hambrick, Sector Policies and Programs Division (E143–05), 109 T.W. Alexander Drive, P.O. Box 12055, Office of Air Quality Planning and Standards, United States Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–0964; and email address: *hambrick.amy@epa.gov.* Individuals who are deaf or hard of hearing, as well as individuals who have speech or communication disabilities may use a relay service. To learn more about how to make an accessible telephone call to any of the numbers shown in this document, visit the web page for the relay service of the Federal Communications Commission. Additional questions may be directed to the following email address: *O&GMethaneRule@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:

APA Administrative Procedure Act
AVO audible, visual, and olfactory
CAA Clean Air Act
CBI Confidential Business Information
CFR Code of Federal Regulations
CRA Congressional Review Act
CVS closed vent systems
ECD enclosed combustion device
EG emissions guidelines
EPA Environmental Protection Agency
FR Federal Register
GC gas chromatograph
GHG greenhouse gas
LPE legally and practicably enforceable
Mcf thousand cubic feet
MS mass spectrometer
NAICS North American Industry Classification System
NIE no identifiable emissions
NHV net heating value
NHV_{cz} combustion zone net heating value
NHV_{dil} dilution parameter net heating value
NSPS new source performance standards
OGI optical gas imaging
OMB Office of Management and Budget
ppmv parts per million by volume
PRA Paperwork Reduction Act
RFA Regulatory Flexibility Act
RULOF remaining useful life and other factors
SEP super emitter program
SIP state implementation plan
TOC total organic compounds
tpy tons per year
UMRA Unfunded Mandates Reform Act
U.S.C. United States Code
VOC volatile organic compound(s)

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Public Participation

Submit your written comments, identified by Docket ID No. EPA–HQ–OAR–2025–0162, at *https://www.regulations.gov* (our preferred method), or by the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to the EPA's docket at *https://www.regulations.gov* any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed in the *Submitting CBI* section of this document. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). Please visit *https://www.epa.gov/dockets/commenting-epa-dockets* for additional submission methods; the full EPA public comment policy; information about CBI or multimedia submissions; and general guidance on making effective comments.

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov.* Clearly mark the part or all the information that you claim to be CBI. For CBI on any digital storage media that you mail to the EPA, note the docket ID, mark the outside of the digital storage media as CBI, and identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in the Public Participation section of this document. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI and note the docket ID. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqps_cbi@epa.gov,* and as described above, should include clear CBI markings, and note the docket ID. 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. If sending CBI information through the postal service, please send it to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2025–0162. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

B. Potentially Affected Entities

The source category that is the subject of this action is the Crude Oil and Natural Gas source category, regulated under Clean Air Act (CAA) section 111. The North American Industry Classification System (NAICS) codes for the industrial source categories affected by the new source performance standards (NSPS) portion of this action are summarized in table 1.

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THE NSPS

Category	NAICS code [1]	Examples of regulated entities
Industry	211120	Crude Petroleum Extraction.
	211130	Natural Gas Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal Government		Not affected.
State and Local Government		Not affected.
Tribal Government	921150	American Indian and Alaska Native Tribal Governments.

[1] North American Industry Classification System (NAICS).

This table is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by the deadline extensions. Other types of entities not listed in the table could also be affected by this action. To determine whether your entity is affected by any of the deadline extensions in this action, you should carefully examine the applicability criteria found in NSPS OOOOb. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

The deadline extensions in EG OOOOc does not impose binding requirements directly on existing sources. The EG codified in 40 CFR part 60, subpart OOOOc, applies to states in the development, submittal, and implementation of state plans to establish performance standards to reduce emissions of greenhouse gases (GHG) from designated facilities that are existing sources on or before December 6, 2022. Under the Tribal Authority Rule (TAR), eligible tribes may seek approval to implement a plan under CAA section 111(d) in a manner similar to a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to a state for purposes of developing a tribal implementation plan (TIP) implementing the EG codified in 40 CFR part 60, subpart OOOOc. The TAR authorizes tribes to develop and implement their own air quality programs, or portions thereof, under the CAA. However, it does not require tribes to develop a CAA program. Tribes may implement programs that are most relevant to their air quality needs. If a tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for designated facilities that are located in areas of Indian country.[1] A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves a TIP applicable to those facilities.

C. Statutory Authority

Statutory authority to issue the amendments finalized in this action is provided by the same CAA provisions that provided authority to issue the regulations being amended: CAA section 111(b)(1)(B) (requirement to review, and if appropriate, revise, standards of performance for new sources at least every 8 years) and CAA section 111(d) (requirement to issue EG for existing sources for certain pollutants to which a NSPS would apply if such existing source were a new source). These statutory provisions, along with administrative agencies' authority to reconsider prior regulations, provide the EPA's statutory authority for the targeted amendments to compliance deadlines finalized in this action.[2]

[1] See the EPA's website, *https://www.epa.gov/tribal/tribes-approved-treatment-state-tas,* for information on those tribes that have treatment as a state for specific environmental regulatory programs, administrative functions, and grant programs.

[2] *See FDA* v. *Wages & White Lion Invs., LLC,* 145 S. Ct. 898 (2025); *FCC* v. *Fox TV Stations, Inc.,* 556 U.S. 502 (2009); *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29 (1983).

Statutory authority for the rulemaking procedures followed in this action is provided by Administrative Procedure Act (APA) section 553(b)(B), 5 United States Code (U.S.C.) 553(b)(B) (good cause exception to notice-and-comment rulemaking), and statutory authority for making this action, which meets the criteria under 5 U.S.C. 804(2), effectively immediately is provided by 5 U.S.C. 808(2). As explained in section III of this preamble, the EPA finds good cause to forego prior notice and comment because such procedures are unnecessary and impracticable under the circumstances detailed in section II of this preamble.

D. 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 September 29, 2025. Under CAA section 307(b)(2), the requirements established by this final action may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

II. Regulatory Revisions

A. Background and Summary

On November 15, 2021, the EPA published a proposed rule (''November 2021 Proposal'') to reduce GHG and volatile organic compound (VOC) emissions from the oil and natural gas industry,[3] specifically the Crude Oil and Natural Gas source category.[4] [5] In the November 2021 Proposal, the EPA proposed revised standards of performance under CAA section 111(b) for GHG and VOC emissions from new, modified, and reconstructed sources in this source category, as well as changes to standards of performance already codified at 40 CFR part 60, subparts OOOO and OOOOa. The EPA also proposed EG under CAA section 111(d) for GHG emissions from existing sources.[6] The EPA also updated the NSPS OOOO and NSPS OOOOa provisions in the Code of Federal Regulations (CFR) in response to Congress' disapproval of the EPA's final rule titled, ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,'' September 14, 2020 (''2020 Policy Rule''), under the CRA. Lastly, the EPA proposed a protocol under the NSPS general provisions for optical gas imaging (OGI).

On December 6, 2022, the EPA published a supplemental proposed rule (''December 2022 Supplemental Proposal'') that was composed of two main additions.[7] First, the EPA proposed to update, tighten, and expand the NSPS OOOOb standards proposed in November 2021 under CAA section 111(b) for GHG and VOC emissions from new, modified, and reconstructed sources. Second, the EPA proposed to update, tighten, and expand the EG OOOOc presumptive standards proposed in November 2021 under CAA section 111(d) for GHG emissions from existing sources. For purposes of EG OOOOc, the EPA also proposed implementation requirements for state plans.

On March 8, 2024, the EPA published a final rule for the Crude Oil and Natural Gas source category under CAA section 111(b) and (d). First, the EPA finalized NSPS OOOOb for GHG and VOC emissions from new, modified, and reconstructed sources in this source category. Second, the EPA finalized EG OOOOc for GHG emissions from existing sources in this source category. Third, the EPA finalized various amendments in response to Congress' disapproval of the 2020 Policy Rule. The 2024 final rule became effective on May 7, 2024.

After publication of the 2024 final rule, the EPA received multiple petitions for reconsideration and has now determined, through ongoing and recent communications with stakeholders and review of the relevant regulatory language, that certain discrete provisions in the final rule present immediate problems related to compliance. The issues raised in petitions for reconsideration that are relevant to this interim final rule are described in individual sections below. In this action, the EPA is amending certain compliance deadlines and timeframes for implementation in response to information received after promulgation of the 2024 final rule to address legitimate concerns, raised by stakeholders, that certain regulatory provisions are not currently workable or contain problematic regulatory language that frustrates compliance.

The 2024 final rule is extensive, covering many individual emissions sources of different types at thousands of facilities in the oil and natural gas source category across the country. As explained in more detail in the sections below, the 2024 rule included several provisions that subsequent developments have shown to be untenable from a compliance perspective on the original timeframes set out in the 2024 rule. These timing difficulties were not anticipated in or intended by the 2024 rule, and it is in the public interest and consistent with the purposes of the CAA to provide regulated entities sufficient time to achieve the emissions reductions envisioned by the 2024 rule. Based on information received in petitions for reconsideration and from ongoing conversations with regulated entities, the EPA finds that the targeted revisions to compliance deadlines set forth below are necessary, appropriate, and consistent with the purposes of the 2024 rule and the CAA.

Each regulatory change included in this final action is severable from the other. First, each of the deadlines amended in this action is functionally independent from the others—*i.e.,* may operate in practice independently of the other requirements being amended here, such that the amendment of a deadline in one set of requirements does not turn on the amendment of a deadline in any other set of requirements. For example, amendments to individual compliance deadlines in NSPS OOOOb function separately from amendments to the state plan submittal deadline in EG OOOOc. Similarly, amendments to the implementation deadline for the Super-Emitter Program and amendments to timing for EPA action on methane detection technology for use in the Super-Emitter Program function separately from amendments to individual compliance deadlines to other aspects of the 2024 final rule. Second, as explained in section II.B of this preamble, the reasoning for each regulatory change is distinct and independent from the others. For

[3] The EPA characterizes the oil and natural gas industry operations as being generally composed of 4 segments: (1) Extraction and production of crude oil and natural gas (''oil and natural gas production''), (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution.

[4] ''*Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.*'' Proposed rule. 86 FR 63110 (November 15, 2021).

[5] The EPA defines the Crude Oil and Natural Gas source category to mean: (1) crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station, commonly referred to as the ''city-gate.''

[6] The term ''designated facility'' means ''any existing facility which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility.'' See 40 CFR 60.21a(b).

[7] ''*Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.*'' Supplemental notice of proposed rulemaking. 87 FR 74702 (December 6, 2022).

example, amendments to individual compliance deadlines in NSPS OOOOb are separately justified, based on the recent information received by the Agency, from the amendments made to the state plan submittal deadline in EG OOOOc based on recent information gathered by the Agency on a distinct set of issues related to OOOOc. Similarly, amendments to individual implementation deadlines for the SEP are separately justified, based on information received by the Agency, from amendments made in response to information received on distinct compliance issues under the other provisions of the 2024 final rule.

The EPA continues to review other issues related to the 2024 final rule that have been brought to the Agency's attention but are not substantively addressed in this action.[8] [9] Thus, this action does not reopen the substance of the 2024 final rule or address the substantive amendments requested in various petitions for reconsideration. As noted in section IV of this preamble, the EPA seeks comment on the compliance deadline amendments at issue in this action and will consider appropriate revisions in reviewing comments. However, the EPA does not seek comment on the substance of the 2024 final rule and will seek and respond to comments on further amendments to the substance of the 2024 final rule at an appropriate time in future rulemaking.

B. Deadline Extensions for NSPS OOOOb [10]

1. Control Devices

In the 2024 final rule, the EPA finalized monitoring requirements for control devices that included vent gas net heating value (NHV) continuous monitoring requirements and an alternative performance test (sampling demonstration) option for flares and enclosed combustion devices (ECDs). In the 2024 final rule, with exceptions for catalytic vapor incinerators, boilers and process heaters, and enclosed combustors where temperature is an indicator of destruction efficiency, all flares and enclosed combustors must maintain the NHV of the gas sent to the device above a minimum NHV if the combustion device is pressure-assisted or uses no assist gas. If an owner or operator uses a steam- or air-assisted flare or ECD, the owner or operator must maintain the combustion zone NHV (NHV_{cz}) above a minimum level. If the owner or operator uses an air-assisted enclosed flare or ECD, the owner or operator must maintain the NHV dilution parameter (NHV_{dil}) above a minimum level. The NHV_{cz} and NHV_{dil} parameter terms account for the reduction in heating value caused by the introduction of air or steam. These terms ensure that the assist gas does not overwhelm the heating value provided by the vent gas to the point where proper combustion is no longer occurring. Owners or operators also have the option to apply to use an alternative test method that either demonstrates continuous compliance with the combustion efficiency limit or directly demonstrates continuous compliance with the NHV_{cz} operating limit and, if applicable, the NHV_{dil} operating limit.

For each flare or ECD used to control gases other than associated gas from a well site affected facility, the owner or operator must conduct continuous monitoring using a calorimeter, gas chromatograph (GC), or mass spectrometer (MS) in order to determine the NHV of the vent stream. As an alternative to continuous monitoring of NHV, the owner or operator may conduct a performance test to demonstrate the NHV of the vent stream consistently exceeds the applicable NHV operating limit in one of two ways: (1) Continuous sampling for 14 consecutive days plus ongoing (3 samples every 5 years) sampling, or (2) manual sampling (twice daily for 14 consecutive days) plus ongoing (3 samples every 5 years) sampling. The minimum collection time for each individual, manually collected sample must be at least 1 hour. If inlet gas flow is intermittent such that collecting 28 samples in 14 days is infeasible, an owner or operator must continue to collect samples beyond 14 days in order to collect a minimum of 28 samples. Owners or operators also have the option to use an alternative test method [11] [12] that demonstrates continuous compliance with the combustion efficiency limit. If there are no values of the combustion efficiency measured by the alternative test method over the 14-day period that are less than 95 percent, the gas stream is considered to consistently exceed the applicable NHV operating limit, and the owner or operator is not required to continuously monitor or conduct sampling of the NHV of the inlet gas to the flare or ECD. Owners or operators of steam-assisted and air-assisted enclosed combustors and flares also must monitor the vent gas and assist gas flow rates and calculate NHV_{cz} and NHV_{dil} in accordance with the provisions in 40 CFR 63.670 (*i.e.,* the refinery maximum achievable control technology rule, or Refinery MACT). Alternatively, owners or operators of air-assisted flares may provide a one-time demonstration based on maximum air assist rates, minimum waste gas flow rates (based on back pressure regulator setting), and minimum NHV from the most recent sampling rather than continuously monitor vent gas and assist gas flow rates.

Multiple petitions for reconsideration and communications with stakeholders after promulgation of the 2024 final rule raised concerns regarding the availability of equipment and personnel necessary [13] to comply with the NHV provisions in the 2024 final rule. Due to the thousands of control devices immediately subject to the OOOOb NHV requirements, number of samples required to be taken, and existing supply chain constraints for monitoring equipment and sampling vendors,[14] petitioners have credibly asserted that

[8] See 90 FR 3734. On January 15, 2025, the EPA proposed amendments to NSPS OOOOb and EG OOOOc in response to petitions for reconsideration. The January 2025 proposal includes discrete technical changes to two aspects of the 2024 final rule. The two issues addressed in the January 2025 proposal are temporary flaring provisions for associated gas in certain situations and vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and ECDs.

[9] In a press release dated March 12, 2025, the EPA Administrator announced various reconsideration efforts including NSPS OOOOb and EG OOOOc. *https://www.epa.gov/newsreleases/trump-epa-announces-oooo-bc-reconsideration-biden-harris-rules-strangling-american.*

[10] Changes made to the SEP discussed in section II.B.6 of this preamble also apply to 40 CFR part 60, subparts OOOO and OOOOa.

[11] Under the provisions outlined in 40 CFR 60.5412b(d) and 60.5415b(f)(1)(xi), sources can request to use an ''equivalent method'' pursuant to 40 CFR 60.8(b)(2), or ''an alternative method the results of which [the Administrator] has determined to be adequate for indicating whether a specific source is in compliance'' pursuant to 40 CFR 60.8(b)(3). The EPA is currently accepting and reviewing applications for alternative (ALT) test methods for NHV monitoring in the oil and natural gas sector. See *https://www.epa.gov/emc/oil-andgas-alternative-test-methods#:~:text=The%20application%20portal%20can%20be,Air%20Emission%20Measurement%20Center%20web page.* Since the rule's publication date of March 8, 2024, two alternative test method requests have been approved by the EPA for use under NSPS subpart OOOOb: (1) ALT–156 Alternative Test Method to monitor the NHV of the flare combustion zone at facilities Subject to NSPS OOOOb and (2) ALT–157 Alternative Test Method for determining NHV from gas sent to an ECD or Flare subject to NSPS OOOOb. A list of the EPA's approved alternative test methods can be found at *https://www.epa.gov/emc/broadlyapplicable-approved-alternative-test-methods.*

[12] Per 40 CFR 60.8(b)(5), the EPA has more general authority to approve alternative test methods involving ''shorter sampling times and smaller sample volumes when necessitated by process variables or other factors.''

[13] See EPA–HQ–OAR–2024–0358–0023 attachment 1 at page 9.

[14] See EPA–HQ–OAR–2024–0358–0016 at page 6.

compliance would be very challenging to achieve within the compliance timeline.[15] Moreover, petitioners credibly asserted that even if the samples could be taken within the prescribed period, there is also insufficient analytical laboratory capacity to conduct the necessary analyses for each sample in a timely manner. One of the petitioners stated that vent gas flow from midstream sources to control devices tends to be sporadic and at low pressure and this is particularly true for storage vessels that either have low flows generally or have pressure control valves that only release short bursts of gas to control devices.[16] Other stakeholders added that even if continuous monitoring was technically feasible, there is a lack of available monitoring equipment,[17] and that it will take owners and operators several months to procure continuous monitoring equipment and installation will take additional time. Furthermore, stakeholders have credibly asserted that discussions with vendors indicated that calorimeters would take between 8 to 12 weeks for delivery and continuous monitoring devices will take up to 26 weeks[18] with installation requiring an additional 2 to 3 weeks.[19]

Additionally, one of the petitioners credibly asserted that the 2024 final rule does not provide an adequate period of time to perform the alternative testing procedures under 40 CFR 60.5412b(d) and does not provide any time for testing at all, putting owners and operators at risk of being deemed out of compliance for operating a modified source before and during testing. The petitioner added that the alternative testing protocol (40 CFR 60.5312b(d)(1)–(5)) requires the combustion device to already be operating in order to determine destruction efficiency and inspect for visible emissions, unlike continuous monitoring, which can be installed prior to the startup of a new source. Therefore, petitioners stated that full compliance with the current deadlines across the industry is not feasible. These concerns have been reiterated[20] in public comments submitted by industry groups on the EPA's proposed reconsideration related to NHV monitoring.[21] Commenters have pointed out that testing equipment requires significant lead times, often multiple months in advance.[22]

In the 2024 final rule, in addition to the NHV requirements described in this section, the EPA also finalized performance testing requirements for ECDs applicable to well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facilities. These performance test requirements consist of a minimum of 3 test runs at least 1 hour long at the inlet of the first control device and at the outlet of the final control device to determine compliance with a total organic compound (TOC) percent reduction requirement of 95.0 percent by weight or greater, or reduce the concentration of TOC in the exhaust gases at the outlet to the control device to a level equal to or less than 275 ppmv as propane on a wet basis corrected to 3 percent oxygen.

According to reconsideration petitioners, the performance testing provisions for ECDs are currently untenable for NSPS OOOOb control devices. Due to the sheer volume of ECDs that require testing under NSPS OOOOb, coupled with the limited number of specialized source testing firms that are available to perform these tests, the petitioners stated that additional time is needed to conduct performance testing for ECDs at affected facilities constructed, modified, or reconstructed since December 6, 2022. The petitioners also expressed concerns over the workload and backlog for the EPA or delegated state and local authorities to process alternative performance testing requests for potentially hundreds of ECD test programs. The petitioners credibly asserted that relying on delegated authorities to address performance testing issues provides no solution on most tribal lands, where the EPA is often the sole agency responsible for implementing NSPS OOOOb.[23] Petitioners stated that while owners and operators utilizing ECDs to comply with standards in a state or Federal plan under EG OOOOc will likely have years to address these challenges, these performance testing issues present an immediate and untenable scenario for NSPS OOOOb control devices.

The petitioners expressed additional concerns over the amount of time required (*i.e.,* minimum test run duration) and the need for supplemental gas to conduct three 1-hour test runs on sources that have intermittent flow (*e.g.,* storage vessels). A testing crew is typically able to conduct up to two performance tests per day where vapor flow is sufficient. Where vapor flow is low and/or intermittent, as can be the case for many storage vessels, it may take multiple days of waiting to find a window with sufficient flow to accommodate a 1-hour test run, and in many cases, there will never be sufficient vapor flow to accommodate a 1-hour test run under normal operating conditions. Therefore, petitioners stated, performing these tests as prescribed in the 2024 final rule is not always feasible.

Additionally, petitioners stated the installation of monitoring equipment or sampling ports on existing ECDs requires specialized ''hot tap'' work. A ''hot tap'' requires specialized vendors and a site shutdown to perform this work. This work exacerbates the already challenging compliance timeline given the existing supply chain constraints, which will prevent most affected facilities from obtaining the necessary monitoring equipment, and the large number of needed retrofits.[24] Therefore, petitioners said this work cannot be accomplished across the industry prior to the deadline for compliance demonstrations.

In this action, the EPA is extending the compliance dates related to NHV monitoring of flares and ECDs found in 40 CFR 60.5417b(d)(8)(i) through (iv) and (vi) by 120 days from publication of this interim final rule to address the supply chain, personnel, and laboratory limitations identified by petitioners which make compliance with the requirements promulgated in the 2024 final rule infeasible. On January 15, 2025, the EPA proposed amendments to the NSPS and EG related to NHV requirements based on reconsideration petitions. The Agency is working towards finalizing those amendments and expects a final rule to be issued soon. Because a separate rulemaking action will address the substantive problems raised with the NHV provisions in the 2024 final rule, we have determined that an extension to November 28, 2025 is sufficient for present purposes. The EPA solicits comments on this extension of 120 days.

[15] See EPA–HQ–OAR–2024–0358–0009 at page 1.

[16] See EPA–HQ–OAR–2024–0358–0016 at page 6.

[17] See EPA–HQ–OAR–2024–0358–0020 attachment 3 at page 5.

[18] See EPA–HQ–OAR–2024–0358–0020 attachment 3 at page 13.

[19] See EPA–HQ–OAR–2024–0358–0013 at pages 2–3.

[20] See EPA–HQ–OAR–2024–0358–0083 at page 16, submitted to the EPA on March 4, 2025.

[21] On January 15, 2025, the EPA proposed amendments to the 2024 final rule based on reconsideration of two discrete issues related to NHV monitoring and temporary flaring. See 90 FR 3734 for the January 2025 reconsideration proposal. See Docket ID No. EPA–HQ–OAR–2024–0358 for public comments submitted on the January 2025 reconsideration proposal.

[22] See EPA–HQ–OAR–2024–0358–0046 at page 8.

[23] See EPA–HQ–OAR–2024–0358–0009 at page 5.

[24] See EPA–HQ–OAR–2024–0358–0009 at page 2 and attachment 1 to the petition.

If, based on comments or otherwise, additional adjustment to the compliance timeline for the NHV requirements is needed, the EPA may address that issue via additional amendments following this action, including potentially in the separate reconsideration action.

Additionally, the EPA is extending the requirement to conduct performance tests on ECDs in 40 CFR 60.5413b(b) until January 22, 2027 to provide affected facilities sufficient lead time to retrofit sources and to plan and execute the performance tests required by the final rule. The EPA notes that even though the Agency is extending the deadline to complete the prescribed NHV monitoring on these source types, the visible emission observation requirements of 40 CFR 60.5417b(d)(8)(v) will continue to apply in order for sources to demonstrate compliance with the prescribed emission standards as of the 2024 final rule effective date of May 7, 2024, or 180 days after startup, whichever is later, as required in 40 CFR 60.5370b(a)(9)(ii).

2. Covers and Closed Vent Systems

As in NSPS OOOO and OOOOa, NSPS OOOOb contains requirements for closed vent systems (CVS) and covers.[25] CVS route emissions from well (*i.e.,* oil wells when routing associated gas to a control device), centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel and process unit affected facilities to a control device or to a process. Pursuant to the 2024 final rule, each CVS used for compliance with an NSPS OOOOb standard must be designed and operated to capture and route all gases, vapors, and fumes to a process or to a control device with ''no identifiable emissions'' (NIE) and these systems must be inspected within 30 days of startup of the affected facility and annually thereafter to verify NIE. Covers must form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel, over the centrifugal compressor wet seal fluid degassing system, or over the reciprocating compressor rod packing emissions collection system. Each cover opening shall be secured in a closed, sealed position (*e.g.,* covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed, except during those times when it is necessary to use an opening, such as to inspect equipment or to remove material from the equipment.

Under the final 2024 rule, initial and continuous compliance of the NIE requirement can be demonstrated through OGI, EPA Method 21, or audio, visual and olfactory inspections (AVO) inspections conducted at the same frequency as the fugitive emissions monitoring for the type of site where the cover and CVS are located. Alternatively, an owner or operator could demonstrate ongoing compliance with the NIE requirement for covers and CVS using the periodic screening or continuous monitoring requirements for advanced methane detection technologies in 40 CFR 60.5398b. Where AVO inspections are required, the CVS and cover are determined to operate with NIE if no emissions are detected by AVO means. Where OGI monitoring is conducted, the CVS and cover are determined to operate with NIE if no emissions are imaged by the OGI camera. Where EPA Method 21 monitoring is conducted, the CVS and covers are determined to operate with NIE if the readings obtained using EPA Method 21 are less than 500 parts per million by volume (ppmv) above background. Emissions detected by AVO, OGI, or EPA Method 21 constitute a deviation of the NIE requirement until a subsequent inspection determines that the CVS and cover operate with NIE. Where monitoring is conducted using advanced methane detection technologies, covers and CVS are determined to operate with NIE if no emissions are detected by the periodic screening survey or, where continuous monitoring is conducted, the site remains under the action levels. If emissions are detected from the site during a periodic screening survey or the site exceeds an action level, the cover and CVS are still determined to operate with NIE unless a follow-up inspection with EPA Method 21, OGI, or AVO indicates that the cover and CVS do not operate with NIE.

Each CVS must be inspected to ensure that the CVS operates with NIE initially within 30 calendar days after startup of the affected facility routing emissions through the CVS. Specifically, for the well sites and centralized production facilities where a CVS is present, quarterly OGI or EPA Method 21 and bimonthly AVO would be required; for compressor stations, quarterly OGI or EPA Method 21 and monthly AVO would be required. For CVS and covers located at onshore natural gas processing plants, AVO inspections are required annually and instrument monitoring for NIE must be conducted either bimonthly with OGI following the procedures in appendix K or quarterly in accordance with EPA Method 21. For CVS joints, seams, and connections that are permanently or semi-permanently sealed, owners and operators are not required to conduct periodic instrument monitoring with OGI or EPA Method 21, but the owner or operator must still conduct initial instrument monitoring and periodic AVO monitoring. Additionally, annual visual inspections must be conducted for all CVS to check for defects, such as cracks, holes, or gaps. If the CVS is equipped with a bypass, the bypass must include a flow monitor and sound an alarm to alert personnel or send a notification via remote alarm to the nearest field office that a bypass is being diverted to the atmosphere, or it must be equipped with a car-seal or lock-and-key configuration to ensure the valve remains in a non-diverting position. To ensure proper design, an assessment of the CVS must be conducted and certified by a qualified professional engineer or inhouse engineer.

Any emissions or defects detected during an inspection of a cover or CVS is subject to repair, with a first attempt at repair within 5 days after detecting the emissions or defect and final repair within 30 days after detecting the emissions or defect. While awaiting final repair, covers must have a gasket-compatible grease applied to improve the seal. Delay of repair is allowed where the repair is infeasible without a shutdown, or it is determined that immediate repair would result in emissions greater than delaying repair. In all instances, repairs must be completed by the end of the next shutdown. Owners and operators may designate parts of the CVS as unsafe to inspect or difficult to inspect but must have a written plan of the inspection of this equipment. Equipment that is unsafe to inspect would expose inspecting personnel to an imminent potential danger; this equipment must be inspected as frequently as practicable, during safe to inspect times. Equipment that is difficult to inspect would require elevating inspecting personnel more than 2 meters above a support surface; this equipment must be inspected at least once every 5 years.

As to this set of issues, the reconsideration petitioners have credibly asserted that it is not technically achievable over the long-term to maintain NIE compliance with these systems.[26] They state that fugitive emissions will occur over time due to normal wear and tear during typical operation of the equipment and leak

[25] Also, as in NSPS OOOOa, CVS and covers that are not associated with an affected facility are fugitive emissions components.

[26] See EPA–HQ–OAR–2024–0358–0009 at page 7.

detection and repair (LDAR) programs are typically designed to allow operators to address them promptly and responsibly.[27] The petitioners state that affected facilities will not be able to prevent inevitable minor fugitive emissions from covers and CVS, and thus the requirement to achieve and maintain NIE is untenable. According to the petitioners, this unrealistic requirement will inevitably yield widespread non-compliance with the NIE requirements in the 2024 final rule due to normal operation of these affected sources because detected leaks are treated as deviations without first allowing for repair.[28] These concerns related to compliance with a requirement viewed as unworkable have been reiterated by stakeholders in subsequent meetings with the EPA.[29 30]

In this action, the EPA is extending the compliance date for NIE requirements until January 22, 2027. Based on information received since promulgation of the 2024 final rule, the EPA has serious concerns regarding the ability of owners/operators to meet the NIE inspection requirements in the 2024 rule on the existing compliance schedule and finds it necessary, appropriate, and in the public interest to extend the compliance deadline given credible workability concerns. We note that other compliance requirements for affected facilities that would otherwise be subject to NIE requirements continue to apply consistent with the substantive requirements and goals of the 2024 final rule. In other words, owners and operators still must design and install a CVS and perform initial and ongoing inspections to ensure that the system has no leaks consistent with the requirements of the 2024 final rule and repair any leaks that are found within 30 days. The only requirements that are being delayed are the inspections to confirm that systems operate with NIE during which identifying a leak would be considered a deviation of the standard.

3. Equipment Leaks

In the 2024 final rule, the EPA promulgated requirements for equipment leaks that included provisions for repairs when equipment leaks are detected. For each valve where a leak is detected, regulated entities must comply by repacking the existing valve with a low emitting (low-E) packing, replacing the existing valve with a low-E valve; or performing a drill and tap repair with a low-E injectable packing.[31] An owner or operator is not required to utilize a low-E valve or low-E packing to replace or repack a valve if the owner or operator demonstrates that a low-E valve or low-E packing is not technically feasible. Low-E valve or low-E packing that is not suitable for its intended use is considered to be technically infeasible. Factors that may be considered in determining technical infeasibility include the following: retrofit requirements for installation (*e.g.,* re-piping or space limitation), commercial unavailability for valve type, or certain instrumentation assemblies.

Reconsideration petitioners have credibly asserted that requiring replacement of leaking valves with low-E valves without first providing an opportunity for an attempt at repair of the existing valve is technically and economically infeasible, did not follow proper notice and comment requirements, and creates confusion regarding when replacement is considered feasible in an enforcement proceeding.[32] Based on cost estimates provided in the petitions for reconsideration, petitioners claim that such equipment (low-E valves and packing) is not commercially available at costs that make widespread replacement of valves with low-E equipment viable across the industry.

The EPA acknowledges that regulatory language in the 2024 final rule introduced unintended compliance difficulties related to equipment leak repair requirements. As currently written, the regulatory language in 40 CFR 60.5400b(h)(2)(ii)(A) appears to require a source to repack an existing valve with low-E packing, and then the language is unclear as to whether a source must also comply with paragraph (B) or (C), which require that they either replace the valve with a low-e valve or perform a drill and tap repair with a low-E injectable packing, respectively. It was not the EPA's intention to require that a source repack an existing valve and replace that valve during the same repair. Furthermore, the CFR erroneously includes two versions of paragraph 60.5401b(i). The EPA discovered since promulgation of the 2024 final rule that these two copies of the repair requirements paragraph differ and create confusion for affected facilities. The first of the two copies included in the CFR is correct while the second contains similar errors to those present in 40 CFR 60.5400b(h)(2)(ii). In order to alleviate the compliance confusion created by the conflicting regulatory language, and to provide potentially affected sources additional time to undertake planning to obtain needed low-e equipment given the cost and widespread need for such equipment, the EPA is extending the compliance date for equipment leak repair requirements contained in 40 CFR 60.5400b(h)(2)(ii) and 60.5401b(i)(2)(ii) until January 22, 2027 or 180 days after startup of the affected source, whichever is later.

4. Process Controllers

Process controllers are automated instruments used for maintaining a process condition, such as liquid level, pressure, pressure difference, or temperature. Historically, in the oil and gas industry, many process controllers were powered by pressurized natural gas and therefore would emit natural gas to the atmosphere. However, process controllers may also be powered by electricity or compressed air, and these types of controllers do not use or emit natural gas. In the December 2022 Supplemental Proposal, the EPA proposed a ''zero emissions'' VOC and methane standard for most process controllers in NSPS OOOOb and a ''zero emissions'' methane presumptive standard for most process controllers in EG OOOOc. This standard can be achieved by using a process controller that is not powered by natural gas, by capturing the emissions from the natural gas-driven controllers and routing them to a process, or by using self-contained controllers. The 2024 final rule includes the ''zero emissions'' VOC standard proposed in December 2022 along with different standards for process controllers in Alaska at locations where access to electrical power from the power grid is not available. The requirements for these sources in Alaska are to use lower emitting natural gas-driven process controllers and to perform inspections to ensure that they are operating properly.

[27] See EPA–HQ–OAR–2024–0358–0012 at page 1.

[28] See EPA–HQ–OAR–2024–0358–0013 at page 14.

[29] See EPA–HQ–OAR–2024–0358–0046 at page 16.

[30] See EPA–HQ–OAR–2024–0358–0023 at page 16.

[31] The 2024 final rule includes the following definitions: *Low-e valve* means a valve (including its specific packing assembly) for which the manufacturer has issued a written warranty or performance guarantee that it will not emit fugitives at greater than 100 ppm in the first five years. A valve may qualify as a low-e valve if it is as an extension of another valve that has qualified as a low-e valve. *Low-e packing* means a valve packing product for which the manufacturer has issued a written warranty or performance guarantee that it will not emit fugitives at greater than 100 ppm in the first five years. Low-e injectable packing is a type of low-e packing product for which the manufacturer has also issued a written warranty or performance guarantee and that can be injected into a valve during a ''drill-and-tap'' repair of the valve.

[32] See EPA–HQ–OAR–2024–0358–0013 at pages 7–11.

The process controller standards apply to the collection of new, modified, and reconstructed natural gas-driven process controllers at a site (*i.e.,* a well site, centralized production facility, onshore natural gas processing plant, or compressor station). Process controllers that are emergency shutdown devices (ESD) or that are not natural gas-driven are not included in the affected facility definition.

The standards that apply differ depending on the location of the site and whether access to electrical power is available at the site, which are sites that have commercial line power onsite. For any site outside of Alaska, the standard for all process controllers is zero emissions of VOC and methane. Zero emissions of VOC and methane may be achieved by using process controllers that are not driven by natural gas (and thus not affected facilities), by routing natural gas-driven process controller vapors through a CVS to a process, by using self-contained natural gas-driven process controllers, or by another means that achieves the numerical standard of zero emissions of methane and VOC. For sites in Alaska with access to electrical power the standard for all process controllers at the site is also zero emissions of VOC and methane. For sites in Alaska without access to electrical power, owners/operators must use natural gas-driven process controllers with low natural gas emission rates. These process controllers include continuous bleed controllers with an emissions rate (or bleed rate) of less than or equal to 6 standard cubic feet per hour (scfh) and intermittent vent controllers, which are process controllers that only emit natural gas when they actuate, rather than emitting continuously. Intermittent vent controllers are subject to monitoring requirements. Further, as an alternative, sites in Alaska without access to electrical power may route emissions from natural gas-driven process controllers to a control device achieving a 95 percent emissions reduction. Table 12 of the March 2024 final rule preamble (89 FR 16882) summarizes the emissions standards for process controllers.

Based on comments the EPA received in 2022 and 2023 expressing concerns about new sources' ability to obtain the equipment necessary to demonstrate compliance with the final standard of zero emissions immediately upon the effective date of the final rule, the EPA finalized a NSPS compliance deadline for process controllers that allows up to 1 year from the effective date of the final rule to come into full compliance with the final standard of zero emissions. Until that final date of compliance, owners and operators must demonstrate compliance with an interim standard which mirrors the requirements for sites in Alaska that do not have access to electrical power. See 89 FR 16929–30.

According to reconsideration petitioners, in the 2024 final rule, existing sites that trigger the OOOOb modification provisions, and thus become subject to the NSPS, have to convert all process controllers in a process controller affected facility to comply with the zero-emission standard by May 7, 2025, or upon modification, whichever is later. Reconsideration petitioners have credibly asserted that this will place a significant demand on the equipment, supplies, and service vendors during the compliance time frame and add more strain to a supply chain that currently requires 12–18 months to deliver certain types of components necessary for the conversion of large natural gas driven controllers to an air driven system.[33] According to petitioners, if an operator is unable to complete the conversion due to reasons beyond its control, the operator will have to make a decision whether to continue operating, potentially in a non-compliant state; or shut down that compressor station, thereby reducing its ability to move gas during peak demand periods, pursuant to their Federal Energy Regulatory Commission approved tariffs.[34] Petitioners also state that the EPA's regulatory language is ambiguous and creates confusion regarding the types of processes potentially subject to the standards. Specifically, petitioners have credibly asserted that the 2024 final rule is unclear with respect to whether certain high-pressure applications are included in the scope of the regulations.[35] Therefore, even more sources may require the equipment necessary to achieve the zero emissions standard which puts even more demand on a limited supply, resulting in further compliance delays that EPA did not intend to create in promulgating the 2024 final rule.

In this final action, the EPA is extending the second phase of the phased-in compliance deadline for the zero emission standards applicable to process controllers to January 22, 2027 to address the supply chain and logistical issues raised by petitioners. The EPA has determined that the additional compliance time is needed to ensure that sufficient equipment can be sourced, obtained, and installed in timelines that are achievable by affected sources. In the meantime, consistent with the substantive provisions and goals of the 2024 final rule, the interim standard continues to apply to process controller affected facilities (*i.e.,* the same standard applicable to sites in Alaska without access to electricity).

5. Storage Vessels

In the 2024 final rule, the EPA promulgated requirements that defined a storage vessel affected facility as a tank battery that has the potential for VOC emissions equal to or greater than 6 tons per year (tpy) or methane emissions equal to or greater than 20 tpy. A storage vessel is a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of non-earthen materials. A tank battery is a group of all storage vessels that are manifolded together for liquid transfer. For purposes of this rule, a tank battery may consist of a single storage vessel if only one storage vessel is present. The 2024 final rule includes language in 40 CFR 60.5365b(e)(ii) that describes how a source should determine the potential emissions from storage vessels. Specifically, the final rule states that potential for VOC and methane emissions must be calculated using a generally accepted model or calculation methodology that accounts for flashing, working, and breathing losses, based on the maximum average daily throughput to the tank battery determined for a 30-day period of production.

Storage vessel affected facilities must reduce emissions of VOC and methane by 95 percent. The standard reflects the degree of emission limitation achievable through application of a combustion control device or vapor recovery unit (VRU). For storage vessel affected facilities not at a well site or centralized production site, and without potential for flashing emissions, owners and operators may choose to comply by using an internal or external floating roof to reduce emissions in accordance with 40 CFR part 60, subpart Kb (NSPS for Volatile Organic Liquid Storage Vessels). The rule allows removal of a control device from a storage vessel affected facility if the owner or operator maintains the uncontrolled actual VOC emissions at less than 4 tpy and the actual methane emissions at less than 14 tpy as determined monthly for 12 consecutive months.

Storage vessel affected facilities which use a control device to reduce emissions must equip each storage

[33] See EPA–HQ–OAR–2024–0358–0014 at page 10.

[34] See EPA–HQ–OAR–2024–0358–0014 at page 10.

[35] See EPA–HQ–OAR–2024–0358–0043 attachment 2 at page 4.

vessel in the tank battery with a cover and must equip the tank battery with one or more CVS which route all emissions to a process or one or more control devices. Owners and operators of flares and other control devices must conduct monitoring, recordkeeping, and reporting to ensure that the control device is continuously achieving the required 95 percent reduction. More information on the flare and other control device monitoring and compliance provisions is provided in section X.H of the March 2024 final rule preamble (89 FR 16963) and information regarding covers and CVS may be found in section X.K of the March 2024 final rule preamble (89 FR 16984).

The EPA finalized an affected facility-specific definition of ''modification'' for storage vessels to include specific physical changes that trigger the modification requirements. Those changes include adding an additional storage vessel, replacing existing storage vessel(s) that result in an increased capacity of the tank battery, receiving additional throughput from production well(s) at tank batteries at well sites or centralized production facilities, or receiving additional fluids which cumulatively exceed the throughput used in the most recent determination of the potential for VOC or methane emissions not located at a well site or centralized production facility, including each tank battery at compressors stations or onshore natural gas processing plants that also result in exceeding the applicability threshold for either VOC or methane. The EPA defined ''reconstruction'' for OOOOb storage vessels to mean at least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel, or the provisions of 40 CFR 60.15 are met for the existing tank battery and the resulting emissions exceed the applicability threshold for either VOC or methane.

Further, in the 2024 final rule, the EPA finalized criteria that must be met for a permit limit or other requirement to qualify as a legally and practicably enforceable (LPE) limit for purposes of determining whether a tank battery is an affected or designated facility under NSPS OOOOb or EG OOOOc, respectively. The 2024 final rule established that a LPE limit must include a quantitative production limit and quantitative operational limit(s) for the equipment, or quantitative operational limits for the equipment; an averaging time period for the production limit, if a production-based limit is used, that is equal to or less than 30 days; established parametric limits for the production and/or operational limit(s), and where a control device is used to achieve an operational limit, an initial compliance demonstration (*i.e.,* performance test) for the control device that establishes the parametric limits; ongoing monitoring of the parametric limits that demonstrates continuous compliance with the production and/or operational limit(s); recordkeeping by the owner or operator that demonstrates continuous compliance with the limit(s) in; and periodic reporting that demonstrates continuous compliance.

Reconsideration petitioners have raised concerns with provisions related to how sources determine potential emissions,[36] the triggers for modification, and the specific criteria for limits on potential to emit to be considered LPE.[37] Some reconsideration petitioners credibly asserted that the applicability determination language in 40 CFR 60.5365b(e)(2)(ii) is ambiguous for tanks that commenced construction, modification, or reconstruction after the date of the supplemental proposal (December 6, 2022) and prior to the OOOOb effective date (''pre-effective date tanks''), May 7, 2024.[38] The petitioners also stated that it is unclear what ''30-day period of production'' operators must use to determine the maximum average daily throughput to calculate the potential for VOC and methane emissions for pre-effective date tanks.[39] Without clarification, operators may not know with certainty the scope of affected storage vessels that must comply with OOOOb by the compliance deadline. The petitioners also credibly asserted that requiring a determination earlier than the OOOOb effective date imposes compliance obligations before they are effective. Additionally, the petitioners stated this is compounded by defining a ''legally and practicably enforceable limit,'' which effectively eliminated the ability to rely on permit limits for applicability determinations under OOOOb. Stakeholders have continued to reiterate these concerns in further discussions with the EPA.[40] Petitioners further stated that the LPE requirements apply to storage vessels for which states do not have the authority or mechanisms to apply such limits in permits.[41]

According to petitioners, the expansive storage vessel modification provisions will immediately and automatically trigger new source requirements for tens of thousands of tanks and tank batteries (far more than the EPA predicted when formulating those provisions). The EPA agrees that the modification provisions finalized in 2024 contain a degree of vagueness such that it is possible that far more midstream storage vessels could trigger modification than the EPA estimated in the 2024 final rule. We did not anticipate that these provisions would affect the large number of sources cited by petitioners and agree that additional compliance time is needed for the large number of potentially affected sources.

The petitioners also stated the EPA should allow more time than afforded in the 2024 final rule to allow state, local, and tribal agencies to adopt and implement conformant LPE limits. The EPA is extending the date for the specific provisions required for a limit to be considered LPE limits in 40 CFR 60.5365b(e)(2)(i)(A)–(F) until January 22, 2027. This action will ensure there is enough time for sources to work with delegated authorities to establish limits that are LPE without foreclosing the use of LPE limits already established that may or may not contain the same level of specificity as the requirements in NSPS OOOOb during that time. Additionally, the EPA is extending the date at which the throughput-based modification triggers become effective by 18 months in order to provide time for the potentially large number of sources that would trigger those provisions to make any needed adjustments to facility planning, equipment procurement, and process changes needed to comply with the requirements. Finally, the EPA is extending the date by which sources must calculate potential emissions using the 30-day period of production by 18 months to allow facilities to obtain additional information and make the requisite decisions related to their facilities that may be subject to these requirements. We note that until the provisions that we are extending come into effect, there are still provisions in place that establish what other activities constitute a modification, *i.e.,* sources that add an additional vessel or replace a vessel with one that has increased capacity still trigger modification. Sources are still required to determine the potential emissions from storage vessels. The only change to these provisions is that, in the interim period, sources need not use the (confusing) 30-day period of production calculation

[36] See EPA–HQ–OAR–2024–0358–0043 at page 17.

[37] See EPA–HQ–OAR–2024–0358–0016 at pages 2–4.

[38] See EPA–HQ–OAR–2024–0358–0009 at page 7.

[39] See EPA–HQ–OAR–2024–0358–0010 at page 5.

[40] See EPA–HQ–OAR–2024–0358–0046 at page 15.

[41] See EPA–HQ–OAR–2024–0358–0043 attachment 2 at page 5.

and limits on potential emissions can be considered LPE with or without the specific criteria included in the 2024 final rule. Any sources that do trigger modification provisions will still be subject to the standards in the 2024 final rule and this action does not change those standards.

6. Super Emitter Program

The EPA included the Super Emitter Program (SEP) in the 2024 final rule, previously proposed as the Super Emitter Response Program in the December 2022 Supplemental Proposal. For purposes of the 2024 final rule, a ''super emitter event'' is defined as any emissions event that is located at or near an oil and natural gas facility and that is detected using remote detection methods and has a quantified emission rate of 100 kg/hr of methane or greater.

As described in the preamble to the 2024 final rule, this program was designed to provide a mechanism by which the EPA would provide owners and operators with timely notifications of super-emitter emissions data collected by EPA-certified third parties using EPA-approved remote sensing technologies. See 89 FR 16877. Where such an event is attributable to an oil or natural gas source regulated under CAA section 111 (NSPS OOOO, OOOOa, or OOOOb, or a state or Federal plan implementing EG OOOOc), the responsible owner or operator would take action in response to such notifications in accordance with the applicable regulation. *Id.* Section X.C of the 2024 final rule preamble describes the SEP in detail. See 89 FR 16876.

In implementing this novel program, the EPA has experienced unanticipated difficulties and concerns that require additional time for effective and lawful administration of various program procedures.[42] For example, while the rule requires a third-party notifier to provide a significant amount of information regarding a super emitter event as part of submitting a notification of the event to the EPA, the attribution of who owns or operates a site is not a required element. While the EPA has developed tools to aid certified third parties in the attribution of identified events, in limited practice, the certified third parties that have submitted information to date have chosen not to include an owner/operator attribution in the submitted notification. In the absence of this information, to meet the program's goals of providing the submitted information about these events to the owners or operators of the appropriate facilities, the EPA must itself determine and then confirm the owner/operator attribution. This process has proven time- and labor-intensive and generated unanticipated concerns about improper attribution and related consequences for enforcement and compliance efforts more generally.

Though the super-emitter program has thus far received relatively few submittals of notifications of super-emitter events from a certified third party, we expect that the number of submittals would grow extensively if more cost-effective technologies were approved (*e.g.,* satellite sensors). With the potential increase in the number of submitted notifications, the EPA's ability to provide timely notification of these events to the facility owner or operator would be hampered given the existing challenges identified in determination attribution for each owner or operator. Similarly, if the number of notifications that the EPA receives based on the currently approved remote-sensing technology were to substantially increase, the EPA's ability to timely provide the notification to the appropriate owner and operator would be constrained by the EPA's ability to make and confirm the owner or operator attribution. These limitations would lead to delays in providing notifications to the appropriate owner or operator that are inconsistent with the program's design and intended function. A central element of the program's design is to provide information about these emissions events in a timely fashion to the appropriate owners and operators, so that they can quickly conduct the investigations into the event required under the rule and take any necessary corrective action if the source is subject to the rule. Delays in providing the notifications to owners and operators would result in the information being stale when received, or superseded by intervening events, limiting both the value of information that could be discovered through the required investigation and the opportunity to take corrective action.

Additionally, implementation of the program to date indicates that application of this program has been broader than the EPA anticipated in promulgating the 2024 final rule. For instance, part of the definition of a super-emitter event under 40 CFR 60.5371b is that the event be located at or near an oil and natural gas facility. In limited practice, this definition has resulted in the EPA receiving notifications of an event at a downstream production site not subject to any upstream oil and gas regulation. Specifically, a notification was provided to a renewable fuel refinery in Bakersfield, California on January 21, 2025. Though this facility is within an oil and gas production basin and an emission was detected from the site, it does not appear to be the type of oil and gas facility that the EPA intended to cover in the SEP. This distinction is important since these types of emissions are likely tied to short-term process conditions which are typical at downstream production sites. While the program requires the EPA to review the submitted notifications of super-emitter events for completeness and accuracy, it does not allow the EPA the discretion to not post or provide a notification to an owner or operator identified in the notification for other reasons, such as the EPA's judgment on the appropriateness of a notification. In the absence of such discretion, the EPA is required to provide a notification to an owner or operator of who is identified in the notification, so long as the EPA had reviewed the notification and determined that it is complete and does not contain information that the EPA finds to be inaccurate to a reasonable degree of certainty, even if other reasons might counsel against providing the notification, such as when that site has already received a notification of a particular emissions event, or if the EPA has determined that a notification relates to an emissions event that is not regulated or prohibited under the EPA's oil and gas rules.

For these reasons, the EPA is extending the date for future implementation of the super-emitter program until January 22, 2027. This extension also impacts the timing for EPA action on methane detection technology under 40 CFR 60.5398b(d)(1)(iii) for use in the SEP. Because the EPA is extending the date for future implementation of the SEP, there is no need for the EPA to act on submissions of remote-detection technology for use in the program in the intervening period. Therefore, the EPA is extending the provisions that include conditional approval of methane detection technology for use in the SEP that occurs if the EPA does not act on submissions of those technologies by the timelines prescribed by the rule until January 22, 2027.

7. Flare Pilot Flame and Alarm Requirements

In the 2024 final rule, the EPA finalized requirements that all enclosed combustion devices, other than boilers and process heaters, that introduce the vent stream with the primary fuel into the flame zone or use the vent stream as the primary fuel, as well as all catalytic

[42] See EPA–HQ–OAR–2024–0358–0010 at 27–32.

incinerators, that operate above a minimum flow rate established by the manufacturer must install and operate a continuous burning pilot or combustion flame. Additionally, the combustion devices must have a way to alert the nearest control room whenever the pilot or combustion flame is unlit.

The 2024 final rule also requires that all flares (*e.g.,* unassisted, pressure-assisted, and steam-assisted) have a continuous burning pilot or combustion flame and have a system that provides an alert to the nearest control room whenever the pilot or combustion flame is unlit. Additionally, the flow rate to a flare must be maintained at a level that ensures compliance with the flare tip velocity limits in the 40 CFR part 60 General Provisions, and the flow rate to an enclosed combustion device must be below a maximum flow rate established during the performance test or by the manufacturer, if the initial performance test is performed by the manufacturer.

Flares and enclosed combustion devices that use pressure-assisted tips to promote mixing at the burner tip are not subject to this maximum flow rate limit because these units are designed to operate at high flow rates. All flares and all enclosed combustion devices used to comply with the standards must also operate with a continuous burning pilot flame and with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. Compliance with the visible emissions requirement can be confirmed either through monthly testing using EPA Method 22 or through continuous use of a video surveillance camera. The 2024 final rule requires that if owners and operators use certain flares and enclosed combustion devices to comply with the standards, they must install a system to send an alarm to the nearest control room if an unlit pilot flame is detected on a flare or enclosed combustion device. Additionally, during each fugitive emissions inspection conducted using an OGI camera, including those conducted in response to periodic screening events using alternative technologies, owners and operators must observe each enclosed combustion device and flare to determine if it is operating properly, including ensuring that a flame is present and that there is no indication of uncontrolled emissions. During each fugitive emissions inspection conducted using AVO, owners and operators must observe each enclosed combustion device and flare to determine if it is operating properly, visually confirming that the pilot flame is lit and operating properly.

Owners and operators also have the option to request an alternative test method to demonstrate continuous 95.0 percent control of emissions. Using this option, the owner or operator would demonstrate that the combustion device continuously achieves 95.0 percent combustion efficiency or that the combustion device continuously complies with the combustion zone NHV and NHV dilution parameter requirements. The alternative test method, if approved by the EPA, would be used in lieu of the other monitoring required for combustion device (*e.g.,* vent gas NHV, flow rate).

In addition to information that must be reported, owners and operators must keep records of continuous compliance with the monitoring requirements, including information about the pilot flame being lit, CPMS limits, CPMS hourly and average values, and results of visible emissions observations or surveillance camera feed.

Petitioners have raised concerns that the 2024 final rule requirements for continuous pilot flames pose significant logistical challenges. These challenges relate to providing supplemental fuel to maintain a continuous pilot flame at intermittently operating processes for affected facilities that are located far from reliable sources of such fuel.[43] Petitioners have also described challenges in obtaining and installing communications equipment capable of reliably transmitting an alarm to the nearest control room.[44] Due to the large number and remote geographic location of many flares and enclosed combustion devices used to achieve compliance with the EPA's standards, industry requires additional time to prepare and install needed equipment to maintain continuous pilot flames that alarm in the nearest control room when the pilot is unlit. Therefore, in this action, we are extending the date by which owners and operators who utilize these flares and enclosed combustion devices must: (1) ensure that flares and enclosed combustion devices operate with a continuous pilot flame, and (2) install and operate a system to send an alarm to the nearest control room when a pilot flame is unlit to 18 months from publication of this interim final rule. The emission reduction requirements for flares and enclosed combustion devices and the other monitoring of such devices described above are not affected by this extension. Put another way, during this extension owners and operators are still required to ensure that emissions being routed to a flare or enclosed combustion devise are reduced by 95.0 percent, and there are still other applicable requirements in the 2024 final rule to ensure compliance.

C. Deadline Extensions for EG OOOOc

1. State Plan Submittal Deadline

In the 2024 final rule, the EPA finalized a state plan submittal deadline of 24 months after publication of the final EG OOOOc (March 9, 2026).[45] While the EPA did not receive any petitions for reconsideration on this deadline, since the rule was finalized, the EPA has regularly engaged with various states regarding their concerns. For example, one state has informally asked their respective EPA Region for an extension of the state plan submittal deadline; other states have been inquiring as to the consequences of late state plan submissions. These compliance assistance efforts from the EPA to the states prompted the EPA to assess the status of the state plan submittals. This assessment has led the EPA to determine that states planning to submit state plans need additional time to develop their plans to achieve the emissions-reduction goals of the 2024 final rule in an effective and efficient manner.

The EPA expects approximately 21 states to submit state plans. Since publication of the 2024 final rule, states should now be approximately halfway completed with the plan development process because state plans are due on March 9, 2026; in other words, we are over 1 year into the 2-year time allowance. For those states relying entirely or mostly on the EPA's model rule included in the final EG without modification, the EPA would expect states to have completed, or be near completing, at least some of the following development milestones: (1) Conduct and document meaningful engagement with pertinent stakeholders pursuant to 40 CFR 60.5363c(a)(6) and 60.23a(i); (2) identify the types of designated facilities within the state that will be covered by the state plan; (3) produce a draft of major portions of the state plan, including standards of performance, compliance schedules, increments of progress, and compliance assurance measures, incorporating relevant sections of the model rule in EG OOOOc; (4) determine and/or draft enforceable regulatory mechanisms to implement the state plan (*e.g.,* general permits, state regulations, etc.); and (5)

[43] See EPA–HQ–OAR–2024–0358–0010 at page 13.

[44] See EPA–HQ–OAR–2024–0358–0010 at page 13–14.

[45] See 89 FR 17010.

notice the draft state plan for public comment in accordance with state laws.

Further, for those states not relying predominantly on the model rule but which are instead leveraging pre-existing state programs and/or invoking remaining useful life and other factors (RULOF) to apply less stringent standards than the presumptive standards in EG OOOOc, the EPA would expect states to have completed, or be near completing, at least some of the following milestones: (1) Conduct and document meaningful engagement with pertinent stakeholders; (2) identify the types of designated facilities within the state that will be covered by the state plan; (3) compile and compare all relevant pre-existing state regulations (or statutes, permits, or other legal authorities) to corresponding coverage of EG OOOOc and determine which state regulations to leverage for purposes of satisfying state plan obligations; (4) determine changes necessary, if any, to harmonize pre-existing state regulations with state plan requirements of EG OOOOc (*e.g.,* changes to designated facilities, designated pollutants, types of standards, etc.); (5) conduct and document analyses to demonstrate equivalency between pre-existing state regulations and EG OOOOc in terms of emissions reductions; (6) begin state rulemaking process to make changes to existing state regulations, if any are necessary; (7) collect and document information to support RULOF demonstrations, if any, for less stringent standards (or longer compliance schedules) than those in EG OOOOc; (8) determine alternative standards to apply in any case where invoking RULOF; and (9) draft other portions of the state plan (those not leveraging pre-existing state regulations and/or invoking RULOF).

The EPA, however, has identified twelve states that have yet to identify how they plan to implement EG OOOOc. Several of these states are still seeking to identify all the potentially impacted facilities within their borders before deciding whether to develop a state plan. The EPA has also identified that 18 of 21 states intending to submit a state plan have yet to share significant portions of those plans with the EPA for feedback. The EPA expects approximately nine states to leverage at least some pre-existing state regulations to satisfy state plan obligations. While at least four states have identified some revisions necessary to harmonize their pre-existing programs with EG OOOOc, the EPA is aware of no state that has begun its rulemaking process to undertake those revisions. Additionally, while the EPA has received numerous questions from states concerning demonstrating equivalency between pre-existing state regulations and EG OOOOc in terms emissions reductions, the EPA has not received any draft analyses for such demonstrations for review. Similarly, while the EPA currently expects approximately five states to invoke RULOF to apply less stringent standards to certain designated facilities, and while the EPA has received numerous questions from states concerning RULOF demonstrations, the EPA has yet to receive any draft RULOF demonstrations for review. The EPA outlines this information in table 2 below. This demonstrates that many states are struggling to develop their plans on the schedule that the 2024 final rule requires.

TABLE 2—STATUS OF STATE AND TERRITORY PLANS

Status	States
I. EPA-Approved State Plans	None.
II. Anticipated Negative Declarations to be Submitted to the EPA.	Hawaii, American Samoa, Guam.
III. Negative Declaration Submitted/EPA Approved.	Vermont (submitted), Puerto Rico (submitted), District of Columbia (submitted).
IV. Anticipated State Plans to be Submitted to the EPA.	Maine, New York, Delaware, Maryland, Pennsylvania, Virginia, West Virginia, Georgia, South Carolina, Tennessee, Arkansas, New Mexico, Oklahoma, Texas, Colorado, Montana, North Dakota, Utah, Wyoming, Arizona, California.
V. Anticipated State Plans Leveraging Pre-Existing State Programs to be Submitted to the EPA.	New York, Maryland, New Mexico, Colorado, Montana, North Dakota, Utah, Wyoming, California.
VI. Anticipated State Plans Invoking RULOF to be Submitted to the EPA.	Tennessee, Arkansas, Oklahoma, Texas, California.
VII. Final State Plans Submitted to the EPA.	None.
VIII. Draft State Plans Submitted to the EPA.	Pennsylvania (partial), West Virginia (partial), Montana (partial).
IX. EPA Has Not Received a Draft or Final State Plan or Negative Declaration.	Maine, New York, Delaware, Maryland, Virginia, Alabama, Florida, Kentucky, Mississippi, North Carolina, Georgia, South Carolina, Tennessee, Illinois, Indiana, Michigan, Minnesota, Ohio, Arkansas, Louisiana, New Mexico, Oklahoma, Texas, Missouri, Colorado, Montana, North Dakota, Utah, Wyoming, Arizona, California, Hawaii, American Samoa, Guam.
X. Anticipated Federal Plan Promulgation.	Connecticut, Massachusetts, New Hampshire, Rhode Island, New Jersey, Wisconsin, Iowa, Kansas, Nebraska, South Dakota, Nevada, Alaska, Idaho, Oregon, Washington.

The EPA acknowledges this delay in meeting expected informal state plan development milestones could be because of various factors, including several that the EPA acknowledged in the 2024 final rule. However, the EPA has determined that the practical reality of states identifying impacted sources and pertinent stakeholders, conducting meaningful engagement, comparing pre-existing state programs to EG OOOOc, and producing RULOF demonstrations has proven to be more time-consuming than we expected because of various challenges faced by states. These challenges stem from both the relatively large and complex nature of the source category, the corresponding complexity associated with applying EG OOOOc to designated facilities, and states' lack of familiarity with the newly revised general implementing regulations.[46]

[46] EG OOOOc represents the first time states will be implementing the requirements promulgated in

States are understandably taking more time than the EPA initially expected as they navigate these multiple challenges, including through iterative questions for and discussions with the Agency.

Moreover, implementing some of these requirements in the context of EG OOOOc in particular is proving to be more complex than originally anticipated. For example, the new requirement to submit documentation of meaningful engagement pursuant to 40 CFR 60.23a(i) has proven time consuming due to the large number of geographically dispersed designated facilities in some states, covering multiple industry segments. States have faced challenges determining the appropriate scope, form, and number of engagement activities, as well as identifying pertinent stakeholders and owners and operators. States have also communicated to the EPA that the relatively complicated technical nature of EG OOOOc has presented obstacles to fostering public participation at engagement activities.

Similarly, states are needing more time than anticipated to invoke RULOF to apply less stringent standards (or longer compliance schedules).[47] For example, due to the large number of EG OOOOc designated facilities, some states have undertaken the task of attempting to segment designated facility types into classes for purposes of RULOF. Given the number and diverse circumstances of designated facilities in the source category, collecting enough information on facility operations necessary to determine appropriate classes and associated standards has proven difficult and time-consuming. For similar reasons, states have confronted difficulties with quickly collecting the full complement of relevant data on emissions and costs to demonstrate fundamental differences between the information specific to those facilities (for which the states are invoking RULOF) and the information the EPA considered in determining the presumptive standards in EG OOOOc.

While the EPA provided flexibility to states with pre-existing regulatory programs for the oil and natural gas industry to leverage those programs for the purposes of state plan submission, the scope and stringency of those programs varies considerably, each posing unique issues regarding demonstrating equivalency or harmonizing with EG OOOOc. Analyses to compare the stringency of pre-existing standards and their associated compliance assurance measures to EG OOOOc have proven to be complicated and time-consuming, especially for those presumptive standards that are expressed in a non-numerical format in EG OOOOc. Administrative complexities have also arisen for several states attempting to concurrently revise associated state rules for Reasonably Available Control Technology in their State Implementation Plans (SIP) for CAA sections 182 and/or 184, in order to maintain a single set of requirements for the oil and natural gas sources in those states.

These challenges have increased the time needed to develop state plans beyond the EPA's expectations. The EPA has worked to provide assistance to states along the way. The EPA has made information publicly available in efforts to helps states including a document summarizing requirements for state plans[48] and answers to frequently asked questions about the 2024 final rule.[49] Additionally, the EPA notes that states have returned multiple times to their Regional offices and the EPA's Office of Air Quality Planning and Standards for numerous meetings to get dozens of complex implementation questions answered, many of which require the coordinated weeks-long effort of multiple EPA staff members to respond to.

Based on the information the EPA currently has, the EPA anticipates the vast majority of states intending to submit state plans will be unable to meet the current state plan submittal deadline of March 9, 2026. If a state does not submit a state plan within the prescribed time, the EPA is obligated to promulgate a Federal plan within twelve months of the submittal deadline.[50] The EPA does not find it appropriate to maintain a state plan submittal deadline that we now have reason to believe is untenable for most states intending to submit state plans. The EPA does not wish to set these states up to fail, especially when they have been diligently working to try to meet the submittal deadline. Extending the submittal deadline will enable states to devote suitable time and resources to developing approvable plans that meet all applicable requirements and achieve the objectives of the states and their stakeholders. In contrast, pressing forward on the existing deadline could needlessly embroil states and the EPA in disputes over untimely or insufficient submissions, thereby triggering administrative processes and litigation that detract from implementation of the emission guidelines and could be avoided with a targeted extension.

In this action we are extending the deadline for state plan submittal until January 22, 2027 for the reasons discussed in this section. This gives states additional time from their current deadline in March 2026.

III. Rulemaking Procedures

As noted in section I.C. of this preamble, the EPA's authority for the rulemaking procedures followed in this action is provided by APA section 553(b)(B), which allows an agency to forgo notice-and comment requirements ''when the Agency for good cause finds (and incorporates the finding and a brief statement of reasons, therefore, in the rule issued) that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest.''[51] The EPA finds good cause to forego prior notice and comment because that rulemaking procedure is impracticable and unnecessary under the circumstances.

The EPA finds that prior notice and comment is unnecessary because the EPA is making only targeted changes to certain compliance or implementation dates in response to immediate concerns raised by stakeholders, including owners and operators subject to the rule's requirements. For the reasons described in more detail in section II of this preamble, certain regulatory provisions have created unintended compliance difficulties unrelated to the actual emissions standards and other requirements of the underlying regulations. This targeted action provides subject facilities the additional time needed to resolve these specific compliance and implementation problems without disrupting the sequencing of the compliance deadlines in the final rule or risking interim noncompliance proceedings. The EPA believes the targeted deadline revisions in this action do not interfere with, or unreasonably frustrate, the ultimate emission reduction requirements of the rule. To the extent interested parties

the revisions to 40 CFR part 60, subpart Ba (subpart Ba), the implementing regulations for the adoption and submission of state plans. 88 FR 80480.

[47] See 40 CFR 60.24a(e)–(h); 88 FR 80508–80528.

[48] *https://www.epa.gov/system/files/documents/2024-08/oooc-summary-of-requirements-for-state-plans-final-8-23-2024.pdf.*

[49] *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations/frequently-asked-questions-about-epas.*

[50] 40 CFR 60.27a(c). The EPA's obligation to promulgate a Federal plan is removed if the state submits, and the EPA approves, a state plan before the EPA issues a Federal plan.

[51] Although the procedural requirements of CAA section 307(d) apply to the EPA's promulgation or revision of any standard of performance under CAA section 111, these procedural requirements do not apply ''in the case of any rule or circumstance referred to in subparagraphs (A) or (B) of [APA section 553(b)].'' 42 U.S.C. 7607(d)(1).

raise concerns about this action or any particular deadline amendment made therein, the EPA will carefully review any comments submitted on this action and consider whether changes are appropriate after close of the comment period.

In addition, the EPA finds that prior notice and comment would be impracticable given the applicable compliance deadlines and the timeline involved in completing such procedures. The EPA has determined through ongoing communications with stakeholders and review of the relevant regulatory language that there are legitimate barriers to compliance and/or questions as to whether the regulatory provisions for which we are extending compliance deadlines are practically and logistically achievable as promulgated in the timeframes allowed by the 2024 final rule. As a result, the EPA is making only targeted changes to certain compliance dates in this action to provide the immediate relief necessary to avoid unnecessary and problematic situations of owners and operators expending time and resources attempting to comply in short amounts of time with untenable regulatory provisions. Prior notice and comment would be impracticable given the purpose of these targeted amendments, which is to provide the immediate extension required to address the problems identified above.

The EPA has determined that this rule may take effect immediately upon publication because, in extending certain deadlines within the 2024 rule it ''relieves a restriction.'' 5 U.S.C. 553(d)(1). Further, for the reasons described above, there exists ''good cause'' for an immediate effective date. 5 U.S.C. 553(d)(3); 5 U.S.C. 808(2).

IV. Request for Comment

As explained in section III of this document, the EPA finds good cause to issue this interim final rule without prior notice or opportunity for public comment. However, the EPA is providing an opportunity for the public to comment on the deadlines being extended in the regulatory text changes being made by this action and, thus, requests comment on the revisions described herein. The EPA is not reopening for comment any provisions of the March 2024 final rule other than the specific changes made in this interim final rule. The EPA will review comments received and consider whether this action should be revised, if appropriate, in response to comments received.

V. 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 as defined under section 3(f)(1) of Executive Order (E.O.) 12866. Accordingly, it was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to E.O. 12866 review have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Economic Impact Analysis for the Extension of Deadlines in the NSPS OOOOb and EG OOOOc,* is available in the docket.

In the analysis, we present the estimated present values (PV) and equivalent annualized values (EAV) of the estimated cost savings of delaying compliance with the EG OOOOc (via extending the state plan submittal deadline) in 2024 dollars over the 2028 to 2039 period, discounted to 2025. Those quantitative results can be found in the next section. We acknowledge, but do not quantify, the cost savings to states resulting from having an additional year to develop state plans to implement the EG OOOOc.

Under the IFR, we anticipate disbenefits associated with additional emissions and lost value of captured natural gas because of delayed compliance with EG OOOOc. Specifically, we estimate climate damages from increasing methane emissions by 1,300,000 short tons, lost value of $PM_{2.5}$ and ozone-related health benefits from increasing VOC emissions by 350,000 short tons, and lost value of benefits from increasing HAP emissions by 13,000 short tons. In addition, we estimate present values of the lost value of natural gas of $170 million using a 3 percent discount rate and $280 million using a 7 percent discount rate.

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 the EPA's analysis of the potential costs and benefits associated with this action. Table 3 presents the estimates of the compliance cost savings of this action. The analysis horizon over which the present value (PV) and equivalent annualized value (EAV) are estimated is 2028 to 2039. We estimate the PV and EAV under 3 and 7 percent discount rates discounted back to 2025 in 2024 dollars.

TABLE 3—PRESENT VALUE (PV) AND EQUIVALENT ANNUALIZED VALUE (EAV) OF THE COMPLIANCE COST SAVINGS
[Billion 2024$, discounted to 2025]

3 Percent discount rate		7 Percent discount rate	
PV	EAV	PV	EAV
0.75	0.08	1.38	0.18

C. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the PRA. On June 28, 2024, the information collection activities for NSPS OOOOb and EG OOOOc were approved by OMB under the PRA.[52] The ICR document that the EPA prepared has been assigned OMB Control No. 2060–0721 and EPA ICR number 2523.07. You can find a copy of the previously submitted ICR in EPA–HQ–OAR–2021–0317.

[52] *https://www.reginfo.gov/public/do/PRAViewICR?ref_nbr=202405-2060-001.*

This action does not change the information collection requirements.

D. Regulatory Flexibility Act (RFA)

This action is not subject to the RFA. The RFA applies only to rules subject to notice and comment rulemaking requirements under the APA, 5 U.S.C. 553, or any other statute. This rule is not subject to notice and comment requirements because the Agency has invoked the APA ''good cause'' exemption under 5 U.S.C. 553(b).

E. Unfunded Mandates Reform Act of 1995 (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local or tribal governments or the private sector. This action extends certain deadlines in the March 2024 final rule.

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. This action extends the deadline for state plan submittals, which will allow additional time for states to develop plans. However, this action does not alter the substantive requirements related to the content of state plans.

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

This action does not have tribal implications as specified in Executive Order 13175. This action will implement extension of certain deadlines in the March 2024 final rule. Thus, Executive Order 13175 does not apply to this action.

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

This action is not subject to Executive Order 13045 because the EPA does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. The EPA contends that the environmental health risks or safety risks addressed by this action do not present a disproportionate risk to children because other regulations are sufficiently protective of children's health. This action does not affect the level of public health and environmental protection already being provided by existing NAAQS and other mechanisms in the CAA. Nor does this action result in any changes to the control of air pollutants. This action does not affect applicable local, state, or Federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions. The EPA does not believe this decrease in emission reductions projected from this action will have a disproportionate adverse effect on children's health.

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. In the Regulatory Impact Analysis (RIA) accompanying the 2024 final rule, the EPA used a set of supply and demand price elasticities to estimate the impacts of the rule on the United States energy system (see section 4.1.4 of that document). The EPA estimated maximum production reductions of about 41.4 million barrels of crude oil (1.05 percent of projected baseline production) and 272.5 million Mcf (thousand cubic feet) per year (0.75 percent). This final rule is estimated to result in a decrease in total compliance costs, with the reduction in costs affecting the affected entities under EG subpart OOOOc, which the EPA expects will attenuate the impacts estimated for the 2024 final rule RIA.

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

This action does not involve technical standards; therefore, the NTTAA does not apply.

K. Congressional Review Act (CRA)

This action meets the criteria described at 5 U.S.C. 804(2), and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. The CRA allows the issuing agency to make a rule effective sooner than otherwise provided by the CRA if the agency makes a good cause finding that notice and comment rulemaking procedures are impracticable, unnecessary, or contrary to the public interest (5 U.S.C. 808(2)). The EPA has made a good cause finding for this action as discussed in section III of this document, including the basis for that finding.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practices and procedures, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Lee Zeldin,

Administrator.

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

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 OOOO—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After August 23, 2011, and On or Before September 18, 2015

■ 2. Amend § 60.5371 by adding two sentences before the first sentence of the introductory text to read as follows:

§ 60.5371 What standards apply to super-emitter events?

The provisions of this section will not apply between July 31, 2025, and January 22, 2027. The provisions of this section will apply after January 22, 2027. * * *

* * * * *

Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After September 18, 2015 and On or Before December 6, 2022

■ 3. Amend § 60.5371a by adding two sentences before the first sentence of the introductory text to read as follows:

§ 60.5371a What standards apply to super-emitter events?

The provisions of this section will not apply between July 31, 2025, and January 22, 2027. The provisions of this section will apply after January 22, 2027. * * *

* * * * *

Subpart OOOOb—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022

■ 4. Amend § 60.5365b by revising paragraph (e)(2)(i) introductory text and paragraphs (e)(2)(ii) and (e)(3)(ii)(C) and (D) to read as follows:

§ 60.5365b Am I subject to this subpart?

* * * * *

(e) * * *

(2) * * *

(i) Beginning January 22, 2027, or upon startup, whichever is later, for purposes of determining the applicability of a storage vessel tank battery as an affected facility, a legally and practicably enforceable limit must include the elements provided in paragraphs (e)(2)(i)(A) through (F) of this section.

* * * * *

(ii) For each tank battery located at a well site or centralized production facility, you must determine the potential for VOC and methane emissions within 30 days after startup of production, or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, except as provided in paragraph (e)(5)(iv) of this section. Beginning January 22, 2027, the potential for VOC and methane emissions must be calculated using a generally accepted model or calculation methodology that accounts for flashing, working, and breathing losses, based on the maximum average daily throughput to the tank battery determined for a 30-day period of production.

* * * * *

(3) * * *

(ii) * * *

(C) Beginning January 22, 2027, or upon startup, whichever is later, for tank batteries at well sites or centralized production facilities, an existing tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of operations or a production well, or changes to operations or a production well (including hydraulic fracturing or refracturing of the well).

(D) Beginning January 22, 2027, or upon startup, whichever is later, for tank batteries not located at a well site or centralized production facility, including each tank battery at compressor stations or onshore natural gas processing plants, an existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (*i.e.,* prior to an action in paragraph (e)(3)(ii)(A), (B), or (D) of this section) determination of the potential for VOC or methane emissions.

* * * * *

■ 5. Amend § 60.5370b by revising paragraph (a) introductory text and paragraphs (a)(4) and (5) and adding paragraphs (a)(8) and (9) to read as follows:

§ 60.5370b When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than May 7, 2024, or upon initial startup, whichever date is later, except as specified in paragraph (a)(1) of this section for reciprocating compressor affected facilities, paragraphs (a)(2) and (3) of this section for storage vessel affected facilities, paragraph (a)(4) of this section for process unit equipment affected facilities at onshore natural gas processing plants, paragraph (a)(5) of this section for process controllers, paragraph (a)(6) of this section for pumps, paragraph (a)(7) of this section for centrifugal compressor affected facilities, paragraph (a)(8) of this section for enclosed combustion devices, paragraph (a)(9) of this section for enclosed combustion devices or flares, and paragraphs § 60.5377b(b) or (c) for associated gas wells.

* * * * *

(4) Except as specified in paragraph (a)(4)(i) and (ii) of this section, you must comply with the requirements of § 60.5400b or as an alternative, the requirements in § 60.5401b, for all process unit equipment affected facilities at a natural gas processing plant, as soon as practicable but no later than 180 days after the initial startup of the process unit.

(i) If complying with § 60.5400b, beginning January 22, 2027, or 180 days after startup, whichever is later, you must comply with the requirements of § 60.5400b(h)(2)(ii).

(ii) If complying with § 60.5401b, beginning January 22, 2027, or 180 days after startup, whichever is later, you must comply with the requirements of § 60.5401b(i)(2)(ii).

(5) For process controller affected facilities, you must comply with the requirements of paragraph (a)(5)(i) or (ii) of this section, as applicable.

(i) Any process controller affected facilities may comply with § 60.5390b(b)(1) and (2) or (3) as an alternative to compliance with § 60.5390b(a) until January 22, 2027.

(ii) On or after January 22, 2027, process controller affected facilities must comply with § 60.5390b(a) or (b), as specified in those paragraphs.

* * * * *

(8) For an enclosed combustion device, you must comply with the requirements of paragraph (a)(8)(i) of this section, as applicable.

(i) Beginning January 22, 2027, or 180 days after startup, whichever is later, you must comply with the performance testing procedures of § 60.5413b(b).

(ii) [Reserved]

(9) For an enclosed combustion device or for a flare, you must comply with the requirements of paragraph (a)(9)(i), (ii), or (iii) of this section, as applicable.

(i) Beginning November 28, 2025, or 180 days after startup, whichever is later, you must comply with the continuous monitoring systems requirements of § 60.5417b(d)(8)(i) through (iv).

(ii) Beginning May 7, 2024 or 180 days after startup, whichever is later, you must comply with the visible emission observation requirements of § 60.5417b(d)(8)(v).

(iii) Beginning November 28, 2025, or 180 days after startup, whichever is later, you must comply with the continuous monitoring systems requirements of § 60.5417b(d)(8)(vi) for enclosed combustion devices or flares that are air-assisted or steam-assisted.

* * * * *

■ 6. Amend § 60.5371b by adding two sentences before the first sentence of the introductory text to read as follows:

§ 60.5371b What GHG and VOC standards apply to super-emitter events?

The provisions of this section will not apply between July 31, 2025, and January 22, 2027. The provisions of this section will apply after January 22, 2027. * * *

* * * * *

■ 7. Amend § 60.5375b by revising paragraphs (a)(2) and (f)(3)(i) and (ii) to read as follows:

§ 60.5375b What GHG and VOC standards apply to well completions at well affected facilities?

(a) * * *

(2) If it is technically infeasible to route the recovered gas as required in paragraph (a)(1)(ii) of this section, then you must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. After January 22, 2027, completion combustion devices must be equipped with a reliable continuous pilot flame.

* * * * *

(f) * * *

(3) * * *

(i) Route all flowback to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. After January 22, 2027, completion combustion devices must be equipped with a reliable continuous pilot flame.

(ii) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. You must have the separator onsite or otherwise available for use at the wildcat well, delineation well, or low pressure well. The separator must be available and ready for use to comply with paragraph (f)(3)(ii) of this section during the entirety of the flowback period. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. After January 22, 2027, completion combustion devices must be equipped with a reliable continuous pilot flame.

* * * * *

■ 8. Amend § 60.5390b by revising paragraph (a) introductory text to read as follows:

§ 60.5390b What GHG and VOC standards apply to process controller affected facilities?

* * * * *

(a) Beginning January 22, 2027, or upon startup, whichever is later, you must design and operate each process controller affected facility with zero methane and VOC emissions to the atmosphere, except as provided in paragraph (b) of this section.

* * * * *

■ 9. Amend § 60.5398b by revising paragraph (d)(1)(iii) to read as follows:

§ 60.5398b What alternative GHG and VOC standards apply to fugitive emissions components affected facilities and what inspection and monitoring requirements apply to covers and closed vent systems when using an alternative technology?

* * * * *

(d) * * *

(1) * * *

(iii) Within 270 days of receipt of an alternative test method request that was determined to be complete, the Administrator will determine whether the requested alternative test method is adequate for indicating compliance with the requirements for monitoring fugitive emissions components affected facilities in § 60.5397b and continuous inspection and monitoring of covers and closed vent systems in § 60.5416b and/or for identifying super-emitter events in § 60.5371b, except that the Administrator is not required to make determinations on such requests for methods for identifying super emitter events in § 60.5371b before January 22, 2027. The Administrator will issue either an approval or disapproval in writing to the submitter. Approvals may be considered site-specific or more broadly applicable. Broadly applicable alternative test methods and approval letters will be posted at *https://www.epa.gov/emc/oil-and-gas-approved-alternative-test-methods-approvals.* If the Administrator fails to provide the submitter a decision on approval or disapproval within 270 days, the alternative test method will be given conditional approval status and posted on this same web page, except that conditional approval will not be given for purposes of identifying super-emitter events in § 60.5371b before January 22, 2027. If the Administrator finds any deficiencies in the request and disapproves the request in writing, the owner or operator may choose to revise the information and submit a new request for an alternative test method.

* * * * *

■ 10. Amend § 60.5411b by revising paragraphs (a)(3) and (b)(4) to read as follows:

§ 60.5411b What additional requirements must I meet to determine initial compliance for my covers and closed vent systems?

* * * * *

(a) * * *

(3) Beginning January 22, 2027, or upon startup, whichever is later, you must design and operate the closed vent system with no identifiable emissions as demonstrated by § 60.5416b(a) and (b).

* * * * *

(b) * * *

(4) Beginning January 22, 2027 or upon startup, whichever is later, you must design and operate the cover with no identifiable emissions as demonstrated by § 60.5416b(a) and (b), except when operated as provided in paragraphs (b)(2)(i) through (iv) of this section.

* * * * *

■ 11. Amend § 60.5412b by revising paragraphs (a)(1)(viii), (a)(3)(viii), and (d)(5) to read as follows:

§ 60.5412b What additional requirements must I meet for determining initial compliance of my control devices?

* * * * *

(a) * * *

(1) * * *

(viii) After January 22, 2027, you must install and operate a continuous burning pilot or combustion flame. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

* * * * *

(3) * * *

(viii) After January 22, 2027, you must install and operate a continuous burning pilot or combustion flame. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

* * * * *

(d) * * *

(5) If the alternative test method demonstrates compliance with the metrics specified in paragraphs (d)(1)(i) and (ii) of this section instead of demonstrating continuous compliance with 95.0 percent or greater combustion efficiency, after January 22, 2027, you must still install the pilot or combustion flame monitoring system required by § 60.5417b(d)(8)(i). If the alternative test method demonstrates continuous compliance with a combustion efficiency of 95.0 percent or greater, the requirement in § 60.5417b(d)(8)(i) no longer applies.

■ 12. Amend § 60.5413b by revising paragraph (e)(2) to read as follows:

§ 60.5413b What are the performance testing procedures for control devices?

* * * * *

(e) * * *

(2) After January 22, 2027, a pilot or combustion flame must be present at all times of operation. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

* * * * *

■ 13. Amend § 60.5415b by revising paragraph (f)(1)(vii)(A)(*1*) and paragraph (h)(1) introductory text to read as follows:

§ 60.5415b How do I demonstrate continuous compliance with the standards for each of my affected facilities?

* * * * *

(f) * * *

(1) * * *

(vii) * * *

(A) * * *

(*1*) After January 22, 2027, a pilot or combustion flame must be present at all times of operation. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

* * * * *

(h) * * *

(1) Beginning January 22, 2027, or upon startup, whichever is later, you must demonstrate that your process controller affected facility does not emit any VOC or methane to the atmosphere

by meeting the requirements of paragraph (h)(1)(i) or (ii) of this section.

* * * * *

■ 14. Amend § 60.5416b by revising paragraphs (a)(1) and (2) and (a)(3)(i) and paragraph (b) introductory text to read as follows:

§ 60.5416b What are the initial and continuous cover and closed vent system inspection and monitoring requirements?

* * * * *

(a) * * *

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.,* a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) through (iii) of this section.

(i) Within the first 30 calendar days after January 22, 2027, or upon startup of the affected facility routing emissions through the closed vent system, whichever is later, conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no identifiable emissions.

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. Beginning on the first annual inspection after January 22, 2027, and for all annual inspections thereafter, you must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no identifiable emissions following any time the component is repaired or replaced or the connection is unsealed.

(iii) Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site as specified in § 60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph (a)(1)(ii) of this section.

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iv) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section within the first 30 calendars days after startup of the affected facility routing emissions through the closed vent system or January 22, 2027, whichever is later, to demonstrate that the closed vent system operates with no identifiable emissions.

(ii) Beginning January 22, 2027, conduct inspections according to the test methods, procedures, and frequencies specified in paragraph (b) of this section to demonstrate that the components or connections operate with no identifiable emissions.

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. Beginning January 22, 2027, you must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no identifiable emissions following any time the component is repaired or replaced or the connection is unsealed.

(iv) Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site, as specified in § 60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph (a)(2)(iii) of this section.

(3) * * *

(i) Beginning January 22, 2027, conduct the inspections specified in paragraphs (a)(3)(ii) through (iv) of this section to identify defects that could result in air emissions and to ensure the cover operates with no identifiable emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

* * * * *

(b) *No identifiable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system and cover as specified in paragraph (a)(1), (2), or (3) of this section or § 60.5398b(b), you must meet the requirements of paragraphs (b)(1) through (9) of this section after January 22, 2027. You must meet the requirements of paragraphs (b)(1), (2), (4), and (9) of this section for each self-contained process controller at your process controller affected facility as specified at § 60.5390b(a)(2).

* * * * *

■ 15. Amend § 60.5417b by revising paragraphs (d)(8)(i) and (i)(6)(v) to read as follows:

§ 60.5417b What are the continuous monitoring requirements for my control devices?

* * * * *

(d) * * *

(8) * * *

(i) After January 22, 2027, continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.

* * * * *

(i) * * *

(6) * * *

(v) After January 22, 2027, if required by paragraph (i)(5) of this section to install a pilot or combustion flame monitoring system, a deviation occurs when there is no indication of the presence of a pilot or combustion flame for any 5-minute period.

* * * * *

Subpart OOOOc—Emissions Guidelines for Greenhouse Gas Emissions From Existing Crude Oil and Natural Gas Facilities

■ 16. Amend § 60.5362c by revising paragraph (c) to read as follows:

§ 60.5362c Am I affected by this subpart?

* * * * *

(c) You must submit the state or Tribal plan or negative declaration letter to EPA by January 22, 2027.

■ 17. Revise § 60.5368c to read as follows:

§ 60.5368c What if my state or Tribal plan is not approvable?

If you do not submit a state or Tribal plan (or a negative declaration letter) by January 22, 2027, or if EPA disapproves your state plan, EPA will develop a Federal plan according to § 60.27a(c) through (f) to implement the emission guidelines contained in this subpart.

■ 18. Amend § 60.5374c by revising paragraph (b) to read as follows:

§ 60.5374c Does this subpart directly affect designated facility owners and operators in my state?

* * * * *

(b) If you do not submit a plan to implement and enforce the guidelines contained in this subpart by the date specified in § 60.5352c, or if EPA disapproves your plan, the EPA will implement and enforce a Federal plan, as provided in § 60.5368c, to ensure that each designated facility within your state that commenced construction, modification or reconstruction on or before December 6, 2022, reaches compliance with all the provisions of this subpart by the dates specified in § 60.5360c.

[FR Doc. 2025–14531 Filed 7–30–25; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 81

[EPA–R02–OAR–2025–0004; FRL–12573–01–R2]

Finding of Failure To Attain and Reclassification of Area in New York as Serious for the 2015 Ozone National Ambient Air Quality Standards—Shinnecock Indian Nation

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final determination.

SUMMARY: The Environmental Protection Agency (EPA) is determining that Indian country under the jurisdiction of the Shinnecock Indian Nation located within the New York-Northern New Jersey-Long Island nonattainment area (Shinnecock Indian Nation area) failed to attain the 2015 ozone National Ambient Air Quality Standards (NAAQS) by the applicable attainment date. The effect of failing to attain by the applicable attainment date is that the area will be reclassified by operation of law to ''Serious'' nonattainment for the 2015 ozone NAAQS on September 2, 2025, the effective date of this final rule. This action fulfills the EPA's obligation under the Clean Air Act (CAA) to determine whether ozone nonattainment areas attained the NAAQS by the attainment date and to publish a document in the **Federal Register** identifying each area that is determined as having failed to attain and identifying the reclassification.

DATES: This final rule is effective on September 2, 2025.

ADDRESSES: The EPA has established a docket for this action under Docket ID Number EPA–R02–OAR–2025–0004 at *https://www.regulations.gov.* All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed in the index, some information is not publicly available, *e.g.,* Controlled Unclassified Information (CUI) (formally referred to as 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 in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Fausto Taveras, Environmental Protection Agency, 290 Broadway, New York, New York 10007–1866, at (212) 637–3378, or by email at *Taveras.Fausto@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document whenever ''we,'' ''us,'' or ''our'' is used, we mean EPA.

Table of Contents

I. Overview of Action

The EPA is required to determine whether areas designated nonattainment for an ozone NAAQS attained the standard by the applicable attainment date, and to take certain steps for areas that failed to attain (*see* CAA section 181(b)(2)). The EPA's determination of attainment for the 2015 ozone NAAQS is based on a nonattainment area's design value (DV) as of the attainment date.[1]

The 2015 ozone NAAQS is met at an EPA regulatory monitoring site when the DV does not exceed 0.070 parts per million (ppm). For the Moderate nonattainment area for the 2015 ozone NAAQS addressed in this action, the attainment date was August 3, 2024. Because the DV is based on the three most recent, complete calendar years of data, attainment must occur no later than December 31 of the year prior to the attainment date (*i.e.,* December 31, 2023, in the case of Moderate nonattainment areas for the 2015 ozone NAAQS). As such, the EPA's determinations for each area are based upon the complete, quality-assured, and certified ozone monitoring data from calendar years 2021, 2022, and 2023.

In 2024, New Jersey, New York, and Connecticut each submitted a request that EPA reclassify the New York-Northern New Jersey-Long Island ozone nonattainment area from Moderate to Serious nonattainment for the 2015 ozone NAAQS.[2] EPA finalized the reclassification in a July 25, 2024 **Federal Register** notice, 89 FR 60314, in which we made clear that since the Shinnecock Indian Nation, which is located adjacent to Southampton, New York, had not requested reclassification of the Shinnecock Indian Nation area of the New York-Northern New Jersey-Long Island nonattainment area for the 2015 ozone NAAQS, it would retain the Moderate classification. This action addresses the Shinnecock Indian Nation area in New York that remains classified as Moderate for the 2015 ozone NAAQS Table 1 provides a summary of the DVs and the EPA's air quality-based determinations for the Shinnecock Indian Nation area addressed in this action.[3]

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[1] A DV is a statistic used to compare data collected at an ambient air quality monitoring site to the applicable NAAQS to determine compliance with the standard. The data handling conventions for calculating DVs for the 2015 ozone NAAQS are specified in appendix U to 40 CFR part 50. The DV for the 2015 ozone NAAQS is the 3-year average of the annual fourth highest daily maximum 8-hour average ozone concentration. The DV is calculated for each air quality monitor in an area, and the DV for an area is the highest DV among the individual monitoring sites located in the area.

[2] Connecticut requested reclassification from moderate to Severe or, in the alternative, to Serious if the States of both New York and Connecticut did not both submit requests to reclassify the area to Severe but did submit requests to reclassify the area to Serious. See 89 FR 60314 (July 25, 2024).

[3] Since the Shinnecock Nation is located within the geographic boundaries of the New York-Northern New Jersey-Long Island nonattainment area, that nonattainment area's design value and the EPA's air-quality based determination will be used as a basis to determine if the Shinnecock Indian Nation attained the August 3, 2024, 2015 ozone NAAQS Moderate attainment date.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2024–0358; FRL–12031–02–OAR]

RIN 2060–AW35

Reconsideration of Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is finalizing amendments to the New Source Performance Standards (NSPS) and Emission Guidelines (EG) for Existing Sources for the Crude Oil and Natural Gas Source Category in response to petitions for reconsideration of the March 8, 2024, final rule. Specifically, this action finalizes discrete technical changes to two aspects of the rules. First, this action finalizes discrete technical changes to the temporary flaring provisions for associated gas in certain situations. Second, this action finalizes discrete technical changes to the vent gas net heating value (NHV) continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and enclosed combustion device(s) (ECD). In a letter dated May 6, 2024, the EPA notified petitioners and the public that the Agency granted reconsideration on these two aspects of the final rule. These amendments neither finalize changes to any other aspect of the March 8, 2024, final rule, nor finalize alterations to the substance of any emission standards within that final rule. This action also finalizes a technical correction to reinstate regulatory text for the reporting requirements in 40 CFR 60.5420b(b)(1) through (15), which were mistakenly deleted by the December 2025 Final Rule. Also, in this action, the EPA finalizes changes to the regulatory text to meet the Office of the Federal Register formatting and style requirements.

DATES: This final rule is effective on June 8, 2026. The incorporation by reference of certain material listed in the rule is approved by the Director of the Federal Register as of June 8, 2026.

ADDRESSES: The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2024–0358. 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 in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov/.*

FOR FURTHER INFORMATION CONTACT: For questions about this final rule, contact Amy Hambrick, Natural Resources Division (E143–05), 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) 541–0964; and email address: *hambrick.amy@epa.gov.* Additional questions may be directed to the following email address: *O&GMethaneRule@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:

ALT alternative
AGR acid gas removal
APA Administrative Procedure Act
API American Petroleum Institute
ASTM American Society for Testing and Materials
AXPC American Exploration and Production Council
BSER best system of emission reduction
Btu/lb British thermal units per pound
Btu/scf British thermal units per standard cubic feet
°C degrees Celsius
CAA Clean Air Act
CBI Confidential Business Information
CFR Code of Federal Regulations
CO_2 carbon dioxide
CRA Congressional Review Act
DRE destruction removal efficiency
ECD enclosed combustion device(s)
EG emissions guidelines
EIA U.S. Energy Information Administration
EOR enhanced oil recovery
EPA U.S. Environmental Protection Agency
FR Federal Register
GC gas chromatograph
GHG greenhouse gas
HP high-pressure
H_2S hydrogen sulfide
ICR information collection request
IFR interim final rule
LP low-pressure
MACT maximum achievable control technology
MCF thousand cubic feet
MS mass spectrometer
NAICS North American Industry Classification System
NHV net heating value(s)
NHV_{cz} combustion zone NHV
NHV_{dil} NHV dilution parameter
NRU nitrogen removal units
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
OGI Optical Gas Imaging
OMB Office of Management and Budget
PRA Paperwork Reduction Act
RFA Regulatory Flexibility Act
RLSO redline strike out
RTC Response to Comment
scf standard cubic feet
TAR Tribal Authority Rule
TCEQ Texas Commission on Environmental Quality
TXOGA Texas Oil and Gas Association
UMRA Unfunded Mandates Reform Act
U.S. United States
VISR Video Imaging Spectro-Radiometry
VOC volatile organic compound(s)

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

On March 8, 2024, the EPA published a final rule for the Crude Oil and Natural Gas source category under CAA section 111(b) and (d) at 89 FR 16820 (''March 2024 Final Rule''). The EPA finalized NSPS OOOOb for GHG and VOC emissions from new, modified, and reconstructed sources in this source category. The EPA also finalized EG OOOOc for GHG emissions from existing sources in this source category. The March 2024 Final Rule became effective on May 7, 2024. The March 2024 Final Rule applies to thousands of new sources and will apply to hundreds of thousands of existing sources when the EG is implemented in the crude oil and natural gas source category. Crude oil production applicability includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and natural gas production applicability includes processing, transmission, and storage, which includes the well and extends to, but does not include, the local distribution company custody transfer station.

After the publication of the March 2024 Final Rule, the EPA received multiple petitions [1] for reconsideration. On May 6, 2024, we notified certain petitioners and the public that we granted reconsideration on two discrete aspects of the March 2024 Final Rule: the temporary flaring provisions for associated gas in certain situations; and the vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and enclosed combustion devices.[2]

On January 15, 2025, the EPA proposed amendments to the New Source Performance Standards and Emission Guidelines for Existing Sources for the Crude Oil and Natural Gas Source Category in response to these petitions for reconsideration (''January 2025 Proposal'').[3] Specifically, we proposed discrete technical changes to two different aspects of the rules (*i.e.,* technical changes to the temporary flaring provisions for associated gas in certain situations; technical changes to the vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and enclosed combustion devices).· This action finalizes amendments to the March 2024 Final Rule resulting from our reconsideration of these two discrete issues.[4]

On January 20, 2025, the President issued Executive Orders 14154 (Unleashing American Energy) [5] and 14156 (Declaring a National Energy Emergency).[6] Then, on January 31, 2025, the President issued Executive Order 14192 (Unleashing Prosperity through Deregulation).[7] On March 12, 2025, against this backdrop, the EPA announced plans for deregulatory actions to, among other things, unleash American energy.[8] On that same day, and as part of the larger Agency plan, the EPA announced plans to reconsider the regulations promulgated via the March 2024 Final Rule ''to ensure they do not prevent America from unleashing energy dominance.'' [9]

On July 31, 2025, the EPA promulgated an IFR which extended deadlines for certain provisions related to control devices, equipment leaks, storage vessels, process controllers, and covers and closed vent systems in the NSPS OOOOb.[10] Within that IFR, the EPA also extended the date for future implementation of the Super Emitter Program and extended the State plan submittal deadline in the EG OOOOc. In December 2025, the EPA promulgated a final rule which responded to comments received on the July 2025 IFR and concluded that the regulatory amendments made in the IFR were still appropriate after consideration of comments.[11] In response to comments received, the December 2025 Final Rule also provided an additional 180-day extension (from the final rule's effective date) (until June 1, 2026) to the compliance dates related to NHV monitoring of flares and ECD found in 40 CFR 60.5417b(d)(8)(i) through (iv) and (vi), as well as 360 days from the effective date of the December 2025 Final Rule (November 30, 2026) for owners or operators to submit initial annual reports pursuant to 40 CFR 60.5420(b).[12]

In this final rule, the EPA is finalizing changes to two aspects of the March 2024 Final Rule (*i.e.,* temporary flaring and NHV monitoring) after consideration of comments received on the January 2025 Proposal.

First, this action finalizes discrete technical changes to the temporary flaring provisions for associated gas in certain situations. These changes include:

- Extending the baseline time limit for temporary flaring of associated gas in certain situations from 24 hours to 72 hours with allowances to go beyond 72 hours in the event of exigent circumstances such as extreme inclement weather that prevent an owner or operator from safely accessing a well site to resolve an emergency or maintenance issue:
  - Requiring owners and operators to cease flaring as soon as the malfunction is resolved or the temporary flaring limit is reached, whichever occurs first, and
  - Clarifying recordkeeping and reporting requirements to include a written description of the exigent circumstance, steps taken to resolve the issue, date and time when it took place, and the total duration of flaring.

Second, this action finalizes discrete technical changes to the vent gas net heating value (NHV) continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and ECDs. These changes include:

- Revising numerous aspects of vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) options for flares and enclosed combustion devices by:

[1] See Docket No. EPA–HQ–OAR–2024–0358 for petitions for reconsideration received.

[2] See Docket No. EPA–HQ–OAR–2024–0358 for May 6, 2024, letter granting reconsideration.

[3] 90 FR 3734 (January 15, 2025).

[4] In the May 6, 2024, letter to petitioners, the EPA also took the opportunity to clarify the applicable timeframe for performance testing with respect to NHV sampling.

[5] 90 FR 8353 (January 29, 2025).

[6] 90 FR 8433 (January 29, 2025).

[7] 90 FR 9065 (February 6, 2025).

[8] *https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history.*

[9] *https://www.epa.gov/newsreleases/trump-epa-announces-oooo-bc-reconsideration-biden-harris-rules-strangling-american.*

[10] 90 FR 35966 (July 31, 2025).

[11] 90 FR 55671 (December 3, 2025).

[12] See 90 FR at 35970–35972 (July 31, 2025), and 90 FR 55675–55676 (December 3, 2025) for discussion of the rationale for NHV monitoring extension.

◦ Expanding gas streams that are exempt from monitoring due to high NHV content to include all flare types (unassisted and assisted), as well as ECDs for both new and existing sources, and

◦ Requiring NHV monitoring via continuous monitoring or alternative sampling demonstration in cases where inert gases are added, or for other miscellaneous scenarios which decrease the NHV content of the inlet gas stream for all flare types and ECDs for both new and existing sources.

2. Summary of the Major Provisions of This Regulatory Action

After considering comments received on the January 2025 Proposal, the EPA is allowing up to 72 hours for certain types of temporary flaring of associated gas based on information indicating that more than 24 or 48 hours is needed in some instances. While we acknowledge owners or operators have an economic incentive not to flare due to product (natural gas) loss that can equate to lost revenue, we have included a backstop requirement that owners or operators cease flaring after resolving the incident causing the need to flare. Collectively, the EPA is increasing the allowance of temporary flaring to 72 hours and including a backstop requirement, so owners or operators have both the economic incentive and a regulatory obligation to cease flaring of associated gas after an equipment malfunction or failure is addressed.

Additionally, the EPA solicited comments in the January 2025 Proposal on specific situations that would be considered ''exigent circumstances.'' Based on comments received and a re-assessment of data provided to the EPA, we are finalizing an allowance to flare for greater than 72 hours if an exigent circumstance persists and there is a need to extend the temporary flaring duration for maintenance, safety issues, or repairs. While we expect that the vast majority of temporary flaring situations to be addressed within the 72-hour timeframe, we recognize that there may be equipment malfunction incidents that require more than 72 hours to resolve due to circumstances beyond an owner's or operator's control. However, to ensure flaring does not continue beyond the time that is necessary to resolve a malfunction incident, we are including a backstop to this extended timeframe of flaring until such equipment malfunctions during these exigent circumstances are resolved or no longer present, whichever is sooner.

After considering input from commenters, the EPA is finalizing that an ''exigent circumstance'' must be a situation that restricts an owner's or operator's ability to reasonably access a site with the necessary equipment and personnel to address and resolve equipment malfunction incidents that cause the need to temporarily flare associated gas for more than 72 hours.

Lastly, the EPA is finalizing recordkeeping and reporting requirements when exigent circumstances are invoked. The EPA anticipates that exigent circumstances will be invoked only in limited cases, and that these additional recordkeeping and reporting requirements will not add undue burden to owners and operators.

The March 2024 Final Rule requires owners and operators to perform NHV sampling for flares and ECD through continuous monitoring of NHV or through periodic testing with sampling demonstrations. Industry petitioners submitted reconsideration petitions in response to the January 2025 proposal claiming that the compliance demonstrations are unnecessary, technically infeasible, and provide a limited timeline for compliance. The petitioners argued that over 99 percent of historical Btu stream data already complies with the prescribed minimum NHV content values (depending on flare type) outlined in the March 2024 Final Rule. Industry petitioners asserted that NHV content is usually a concern when inert gases are added to the process streams, which typically occurs during scheduled situations and is known to the operator of the affected source. The EPA made amendments to the NHV provisions based on data submitted by industry supporting their claims that the majority (over 99 percent) of facilities already complied with the minimum NHV requirements, and NHV content is only a concern when inert gases (and other miscellaneous scenarios) are added to the process streams.

Based on information from these petitions, as well as further information provided by industry following the January 2025 proposal, the EPA is finalizing changes to the continuous monitoring requirements and alternative performance test options (sampling demonstration) of NHV for flares and ECD. First, the EPA is expanding the gas streams that are exempt from monitoring due to high NHV content to include all flare and ECD for both new and existing sources. However, the EPA is also requiring that NHV monitoring be performed (via either continuous monitoring or the alternative performance test (sampling demonstration) option currently prescribed in the NSPS OOOOb and EG OOOOc regulations) in cases where inert gases are added and for other miscellaneous scenarios which decrease the NHV content of the inlet stream gas to all flare and ECD for both new and existing sources. In addition, the EPA is providing additional flexibility for alternative performance testing via the NHV grab sampling option by allowing samples to be taken upstream of the control device, provided that the sample is representative of the gas being introduced to the control device. Additionally, we are finalizing as proposed to allow breaks during weekends and holidays for the March 2024 Final Rule's consecutive 14-day sampling demonstration requirements to account for reasonable operational pauses provided no sampling is spaced more than 3 operating days apart from the previous sampling day. The EPA is also allowing less than one-hour sampling times in cases where low or intermittent flow makes it infeasible for both NSPS OOOOb and EG OOOOC sources, provided the sampling time used and reason for the reduced sampling time is documented and reported. Finally, the EPA is clarifying NHV testing must be reported in volumetric units (Btu/scf) instead of specific units (Btu/lb) in order to facilitate consistency in reporting.

This action also finalizes a technical correction to reinstate regulatory text for the reporting requirements in 40 CFR 60.5420b(b)(1) through (15), which were mistakenly deleted by the December 2025 Final Rule,[13] under the authority of section 553(b)(B) of the Administrative Procedure Act, 5 U.S.C. 553(b)(B), which states, when an agency for good cause finds that public notice and comment procedures are impracticable, unnecessary, or contrary to the public interest, the agency may issue a rule without providing notice and an opportunity for public comment. Lastly, in this action, the EPA is finalizing formatting changes to the regulatory text to meet the required formatting standards of the Office of the Federal Register.[14]

3. Costs and Benefits

The EPA estimated present values (PV) and equivalent annualized values (EAV) of the estimated cost savings of this final reconsideration in 2024 dollars over the 2024 to 2038 period. The cost savings are represented in this analysis as the reduction in the number of affected sources and a reduction in the number of tests required for each affected source for the changes finalized

[13] 90 FR 55671 (December 3, 2025).

[14] To view the final formatting changes, see the full redline strike out (RLSO) of the regulatory text located in the public docket at EPA–HQ–OAR–2024–0358.

in this reconsideration. In simple terms, these cost savings are an estimate of the decreased industry expenditures resulting from the final changes to the March 2024 Final Rule requirements. Under this final action, emissions changes and benefits from emission changes were not quantified. Qualitatively, the changes to the temporary flaring limitation could result in increases to emissions, while we do not expect any emissions changes to result from the changes to the NHV testing compliance demonstration.

Table 1 presents the estimated cost savings of this proposed action in 2024 dollars for the baseline which includes the March 2024 Final Rule (*i.e.,* the primary baseline analyzed in the EIA). This table presents the PV and EAV of these estimates discounted at three percent and seven percent.

TABLE 1—PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF COMPLIANCE COST SAVINGS ESTIMATES OF THE FINAL ACTION FROM 2024–2038

[Millions of 2024$]

	3 Percent discount rate	7 Percent discount rate
Present Value	2,480	1,900
Equivalent Annualized Value	208	209

B. Does this action apply to me?

The source category that is the subject of this final action is the Crude Oil and Natural Gas Source Category regulated under Clean Air Act (CAA) section 111 through New Source Performance Standards (NSPS) and Emission Guidelines (EG). The 2022 North American Industry Classification System (NAICS) codes for the source category are summarized in Table 2. The NAICS codes serve as a guide for readers outlining the entities that this final action is likely to affect. The NSPS codified in 40 CFR part 60, subpart OOOOb, are directly applicable to affected facilities that begin construction, reconstruction, or modification after December 6, 2022. As shown in Table 1, Federal, State, and local government entities would not be affected by the NSPS action.

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY NSPS ACTION

Category	NAICS code	Examples of regulated entities
Industry	211120	Crude Petroleum Extraction.
	211130	Natural Gas Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal Government		Not affected.
State and Local Government		Not affected.
Tribal Government	921150	American Indian and Alaska Native Tribal Governments.

This table is not intended to be exhaustive but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in the table could also be affected by this action. To determine whether your entity is affected by this action, you should carefully examine the applicability criteria found in NSPS OOOOb and EG OOOOc. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section, your State air pollution control agency with delegated authority for NSPS OOOOb, or your EPA Regional Office.

The issuance of the CAA section 111(d) EG in March of 2024 did not impose binding requirements directly on existing sources. The EG codified in 40 CFR part 60, subpart OOOOc, apply to States in the development, submittal, and implementation of State plans to establish performance standards to reduce emissions of greenhouse gas (GHG) in the form of limitations on methane from designated facilities that commence construction, modification, or reconstruction on or before December 6, 2022. Under the Tribal Authority Rule (TAR), eligible Tribes may seek approval to implement a plan under CAA section 111(d) in a manner similar to a State. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment as a State for purposes of developing a Tribal Implementation Plan (TIP) implementing the EG codified in 40 CFR part 60, subpart OOOOc. The TAR authorizes Tribes to develop and implement their own air quality programs, or portions thereof, under the CAA. However, it does not require Tribes to develop a CAA program. Tribes may implement programs that are most relevant to their air quality needs. If a Tribe does not seek and obtain authority from the EPA to establish a TIP, the EPA has authority to establish a Federal CAA section 111(d) plan for designated facilities that are located in areas of Indian country.[15] A Federal plan would apply to all designated facilities located in the areas of Indian country unless the EPA approves a TIP applicable to those facilities.

C. 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 action is available on the internet. A brief summary of this final rule is available at *https://www.regulations.gov,* Docket ID No. EPA–HQ–OAR–2024–0358. Following signature by the EPA Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations.* Following publication in the **Federal**

[15] See the EPA's website, *https://www.epa.gov/tribal/tribes-approved-treatment-state-tas,* for information on those Tribes that have treatment as a State for specific environmental regulatory programs, administrative functions, and grant programs.

Register, the EPA will post the **Federal Register** version of the final rule and key technical documents at this same website.

A memorandum showing the edits to 40 CFR part 60 subpart OOOOb and 40 CFR part 60 subpart OOOOc finalized in this action is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2024–0358). Following signature by the EPA Administrator, the EPA also will post a copy of this document to *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations.*

II. Statutory Background and Regulatory History

A. CAA Sections 111(b) and 111(d)

The EPA's authority for this rulemaking is CAA section 111, 42 U.S.C. 7411, which governs the establishment of standards of performance for stationary sources. This CAA section requires the EPA to list source categories to be regulated, establish standards of performance for air pollutants emitted by new sources in that source category, and promulgate EG for States to establish standards of performance for certain pollutants emitted by existing sources in that source category. For more information on the statutory background of CAA sections 111(b) and 111(d), and general implementing regulations, refer to the discussion provided in section IV.A (Statutory Background of the CAA sections 111(b), 111(d), and General Implementing Regulations) of the March 2024 final rule preamble. (89 FR 16846–16848; March 8, 2024).

B. What is the regulatory history and background of NSPS and EG for the Crude Oil and Natural Gas source category?

On November 15, 2021, the EPA published a ''proposed rule'' (''November 2021 Action'') to reduce GHG and volatile organic compound (VOC) emissions from the oil and natural gas industry, specifically the Crude Oil and Natural Gas source category, but did not provide proposed regulatory text. In the November 2021 Action, the EPA discussed new standards of performance under CAA section 111(b) for GHG and VOC emissions from new, modified, and reconstructed sources in this source category, as well as changes to standards of performance already codified at 40 CFR part 60, subparts OOOO and OOOOa. The EPA also proposed EG under CAA section 111(d) for GHG emissions from existing sources in this source category for the first time. The EPA also discussed a protocol under the NSPS general provisions for optical gas imaging (OGI).

On December 6, 2022, the EPA published a supplemental proposed rule (''December 2022 Supplemental Proposal'') that addressed two additional issues. First, the EPA proposed to update and expand the NSPS OOOOb standards in the November 2021 Action for GHG and VOC emissions from new, modified, and reconstructed sources. Second, the EPA proposed to update and expand the EG OOOOc standards in the November 2021 Action for GHG emissions from existing sources. For purposes of EG OOOOc, the EPA also proposed implementation requirements for State plans.

On March 8, 2024, the EPA published a final rule for the Crude Oil and Natural Gas source category under CAA section 111(b) and (d) at 89 FR 16820 (''March 2024 Final Rule''). The EPA finalized NSPS OOOOb for GHG and VOC emissions from new, modified, and reconstructed sources in this source category. The EPA also finalized EG OOOOc for GHG emissions from existing sources in this source category. The March 2024 Final Rule became effective on May 7, 2024. The March 2024 Final Rule applies to thousands of new sources and will apply to hundreds of thousands of existing sources when the EG is implemented in the crude oil and natural gas source category. Crude oil production applicability includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and natural gas production applicability includes processing, transmission, and storage, which includes the well and extends to, but does not include, the local distribution company custody transfer station.

After the publication of the March 2024 Final Rule, the EPA identified, through its own internal reassessment, as well as through communications with stakeholders and the Office of the Federal Register, erroneous cross-references and typographical errors within the regulatory text. Through those same processes, the EPA also identified the need for some minor wording changes to clarify erroneous language (or, in some cases, erroneous omissions) in the regulatory text, and to ensure that the regulatory text aligns with the descriptions of the relevant provisions in the March 2024 Final Rule preamble and other parts of the regulation(s). The EPA published an IFR [16] which made minor and non-substantive corrections to the identified inadvertent errors in the March 2024 Final Rule.

Further, after the publication of the March 2024 Final Rule, the EPA received multiple petitions [17] for reconsideration. On May 6, 2024, we notified certain petitioners and the public that we granted reconsideration on two discrete aspects of the March 2024 Final Rule: the temporary flaring provisions for associated gas in certain situations; and the vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and enclosed combustion devices.[18] The American Petroleum Institute (API) and the AXPC,[19] [20] the TXOGA,[21] the GPA Midstream,[22] and the Environmental Integrity Project [23] submitted petitions for reconsideration on those issues. This action finalizes amendments to the March 2024 Final Rule resulting from our reconsideration of these two discrete issues.[24]

[16] 89 FR 62872 (August 1, 2024); Document ID No. EPA–HQ–OAR–2021–0317–4057.

[17] See Docket No. EPA–HQ–OAR–2024–0358 for petitions for reconsideration received.

[18] See Docket No. EPA–HQ–OAR–2024–0358 for May 6, 2024, letter granting reconsideration.

[19] Letter to Michael S. Regan, EPA Administrator, from API and AXPC. Re: Provisions in the EPA's Final Rule ''New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review.'' Reconsideration of the Final Rule. April 5, 2024. Hereinafter referred to as the ''April 2024 API and AXPC petition.''

[20] Letter to Michael S. Regan, EPA Administrator, from API and AXPC. Re: Request for Administrative Reconsideration of EPA's Final Rule ''New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review'' May 6, 2024. Hereinafter referred to as the ''May 2024 API and AXPC petition.''

[21] Letter to Michael S. Regan, EPA Administrator, from TXOGA. Request for Reconsideration of the EPA's Final Rule ''New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review.'' May 7, 2024. Hereinafter referred to as the ''May 2024 TXOGA petition.''

[22] Letter to Michael S. Regan, EPA Administrator; Gautam Srinivasan, Associate General Counsel, EPA; and Amy Hambrick, SPPD, EPA; from GPA Midstream Association. GPA Midstream Association Petition for Reconsideration and Request for Stay of Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. May 2, 2024. Hereinafter referred to as the ''May 2024 GPA Midstream petition.''

[23] Letter to Michael S. Regan, EPA Administrator, from Air Alliance Houston; Clean Air Council; and Environmental Integrity Project. Re: Petition for Reconsideration of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review; Final Rule, 89 FR 16,820 (March 8, 2024), Docket No. EPA–HQ–OAR–2021–0317. May 7, 2024. Hereinafter referred to as the ''May 2024 EIP et al. petition.''

[24] In the May 6, 2024, letter to petitioners, the EPA also took the opportunity to clarify the

On January 20, 2025, the President issued Executive Orders 14154 (Unleashing American Energy)[25] and 14156 (Declaring a National Energy Emergency).[26] Then, on January 31, 2025, the President issued Executive Order 14192 (Unleashing Prosperity through Deregulation).[27] On March 12, 2025, against this backdrop, the EPA announced plans for deregulatory actions to, among other things, unleash American energy.[28] On that same day, and as part of the larger Agency plan, the EPA announced plans to reconsider the regulations promulgated via the March 2024 Final Rule ''to ensure they do not prevent America from unleashing energy dominance.''[29]

On July 31, 2025, the EPA promulgated an IFR which extended deadlines for certain provisions related to control devices, equipment leaks, storage vessels, process controllers, and covers and closed vent systems in the NSPS OOOOb.[30] Within that IFR, the EPA also extended the date for future implementation of the Super Emitter Program and extended the State plan submittal deadline in the EG OOOOc. In December 2025, the EPA promulgated a final rule which responded to comments received on the July 2025 IFR and concluded that the regulatory amendments made in the IFR were still appropriate after consideration of comments.[31] In response to comments received, the December 2025 Final Rule also provided an additional 180-day extension (from the final rule's effective date) (until June 1, 2026) to the compliance dates related to NHV monitoring of flares and ECD found in 40 CFR 60.5417b(d)(8)(i) through (iv) and (vi), as well as 360 days from the effective date of the December 2025 Final Rule (November 30, 2026) for owners or operators to submit initial annual reports pursuant to 40 CFR 60.5420(b).[32]

C. Judicial Review and Administrative Review

Under CAA section 307(b)(1), judicial review of this final rulemaking is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by June 8, 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. 42 U.S.C. 7607(b)(1)–(2).

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.'' 42 U.S.C. 7607(d)(7)(B). 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.

III. Summary of Final Amendments to NSPS OOOOb and EG OOOOc

The amendments in this final action relate to two aspects of the March 2024 Final Rule: the temporary flaring provisions for associated gas in certain situations; and the vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and enclosed combustion devices. The two issues addressed in this final rule are separate and distinct from each other. Each of these two issues concern different portions of the March 2024 Final Rule that do not rely on the other. This action also finalizes a technical correction to reinstate regulatory text for the reporting requirements in 40 CFR 60.5420b(b)(1) through (15), which were mistakenly deleted by the December 2025 Final Rule.[33] Also, in this action, the EPA is finalizing formatting changes to the regulatory text to meet the required formatting standards of the Office of the Federal Register.[34]

Each regulatory change included in this final action is severable from the other. First, each of the two groups of substantive provisions amended in this action (temporary flaring of associated gas and vent gas NHV) is functionally independent from the other—*i.e.,* may operate in practice independently of the other requirements being amended here, such that the amendment of one set of requirements does not turn on the amendment of any other set of requirements. Put another way, the amendments to the temporary flaring provisions in no way impact or depend on the separate amendments to the NHV provisions. The same is true in the opposite direction. The amendments to the NHV provisions in no way impact or depend on the separate amendments to the temporary flaring provisions. Second, as explained in this final rule preamble and the preamble to the proposed rule, the reasoning for each regulatory change is distinct and independent from the others. For example, amendments to the NHV provisions are separately justified from the amendments made to the temporary flaring of associated gas provisions. Again, the same is true in the opposite direction. Amendments to the temporary flaring of associated gas provisions are separately justified from the amendments made to the NHV provisions. Likewise, the formatting changes are also separate, distinct, and severable.

A. Temporary Flaring Provisions for Associated Gas in Certain Situations

Section XI.F.2 of the March 2024 Final Rule preamble presents a discussion of reasons why an owner or operator would need to flare or vent associated gas. Based on the reasons set out in that preamble, the EPA in the March 2024 Final Rule allowed owners and operators to temporarily route associated gas to a flare or control device for 24 hours in certain situations, including during a deviation caused by a malfunction (including for reasons of safety) and during repair, maintenance such as blowdowns, a bradenhead test, a packer leakage test, a production test, or commissioning. On January 15, 2025, the EPA proposed extending the allowable time for these situations from

applicable timeframe for performance testing with respect to NHV sampling.

[25] 90 FR 8353 (January 29, 2025).

[26] 90 FR 8433 (January 29, 2025).

[27] 90 FR 9065 (February 6, 2025).

[28] *https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history.*

[29] *https://www.epa.gov/newsreleases/trump-epa-announces-oooo-bc-reconsideration-biden-harris-rules-strangling-american.*

[30] 90 FR 35966 (July 31, 2025).

[31] 90 FR 55671 (December 3, 2025).

[32] See 90 FR at 35970–35972 (July 31, 2025), and 90 FR 55675–55676 (December 3, 2025) for discussion of the rationale for NHV monitoring extension.

[33] 90 FR 55671 (December 3, 2025).

[34] To view the final formatting changes, see the full redline strike out (RLSO) of the regulatory text located in the public docket at EPA–HQ–OAR–2024–0358.

24 hours to 48 hours (''January 2025 Proposal'').[35] The EPA proposed the extended temporary flaring limit based in part on data provided by API, which showed that 85 percent of flaring events ended within 46 hours for activities such as maintenance, addressing safety issues, and repairs.

As discussed in section III.A.2 of the preamble to the January 2025 Proposal, industry petitioners indicated that the 24-hour limitation for temporary routing of associated gas to a flare or control device in the March 2024 Final Rule is not sufficient in situations where a malfunction or an unintended incident endangers the safety of operator personnel and the public; as well as during repairs, maintenance (including blow downs), production tests, and commissioning. Petitioners claimed that a 72-hour timeframe for temporarily routing associated gas to a flare or control device for these situations is more appropriate due to the unique characteristics of some well sites (*e.g.,* due to the differing location and composition/amount of gas produced by wells), weather conditions, or a combination of both.

After consideration of comments received on the January 2025 Proposal and revisiting the data API provided to the Agency, the EPA is finalizing two primary changes to the January 2025 Proposal related to the temporary flaring of associated gas. First, the EPA finds that increasing the temporary flaring provisions up to 72 hours is appropriate. This extended timeframe gives owners and operators enough time to travel to facilities (including geographically remote facilities), troubleshoot, obtain necessary equipment, and complete repairs. It also provides sufficient time to overcome many inclement weather situations where access to a site may be temporarily limited. Further, moving to 72 hours will reduce the number of incidents where invoking exigent circumstances is necessary, thus reducing burden on the industry. Lastly, the extended timeframe also reduces the need to shut-in operations (where a well is temporarily closed off to restrict oil and gas flow and production due to unusual or unsafe conditions) in situations where the issue(s) cannot be addressed within 24 or 48 hours. Shutting-in operations can often result in the depressurization of equipment, which may lead to the venting of associated gas to the atmosphere without control. The venting of associated gas in these scenarios may exceed the emissions that would have otherwise occurred if the provisions allowed for an additional 24 hours of flaring thereby defeating the environmental objectives of the rule.[36]

Second, and relatedly, the EPA is requiring owners and operators to stop temporary flaring when repairs or maintenance are completed to avoid flaring longer than necessary during an individual incident. If repair or maintenance is completed within 72 hours, then flaring must stop at the time of completion. In other words, temporary flaring must cease as early as practicable and within 72 hours unless the facility properly invokes the procedures for a longer duration. While the 72 hours is a default maximum duration, if a situation arises that requires an owner or operator to temporarily flare beyond those 72 hours, then the final rule's additional provisions on exigent circumstances may apply. See section IV.A.1 of this preamble for further discussion of exigent circumstances. Also see section IV.A.2 for further discussion on temporary flaring beyond 72 hours.

By finalizing an upper limit of temporary flaring up to 72 hours, the final rule gives operators room to continue to develop ways to manage delays tied to these malfunctions and failures. At the same time, it prevents unnecessary flaring when problems are already fixed, thereby protecting against unnecessary emissions. This balance encourages owners and operators to keep improving how they detect and fix problems while providing flexibility and relief. It also supports better planning, faster repairs, and the potential for greater emission reductions in the future.

In summary, the EPA is allowing up to 72 hours for certain types of temporary flaring of associated gas based on information indicating that more than 24 or 48 hours is needed in some instances. While we acknowledge owners or operators have an economic incentive not to flare due to product (natural gas) loss that can equate to lost revenue, we have included a backstop requirement that owners or operators cease flaring after resolving the incident causing the need to flare. Collectively, the EPA is increasing the allowance of temporary flaring to 72 hours and including a backstop requirement, so owners or operators have both the economic incentive and a regulatory obligation to cease flaring of associated gas after an equipment malfunction or failure is addressed.

Petitioners raised inclement weather as a circumstance that may deter an owner or operator from accessing an affected facility site and as a primary cause for the need to temporarily flare (*e.g.,* frozen gas lines, power outages). While the API dataset classifies inclement weather as the cause of 86 flaring events, the dataset classifies the primary cause of over 600 flaring events as ''[u]nknown'' and these events exhibited the highest average flaring durations and standard deviations. While we do not know the exact cause of the over 600 ''unknown'' flaring events in API's data set, maintaining a 24-hour flaring timeframe as promulgated in the March 2024 Final Rule based on the percentage of reported inclement weather-impacted events only presents a narrow reading of the data and does not reflect the unknown flaring events that exhibited the highest flaring durations and standard deviations. The EPA recognizes that the API data show that many temporary flaring events are resolved within 24 hours, and even more within 48 hours. Specifically, 83 percent of the instances were resolved within 24 hours and 85 percent within 48 hours. The EPA considered establishing cutoffs at 24 hours or 48 hours. However, the data indicate that 15 percent of instances could not be resolved within 48 hours. Industry noted that weather is a factor, but not the only factor, impacting temporary flaring events longer than 24 hours, and geographically dispersed sites, such as the Willison Basin which contained the majority (78%) of the >24 hour flaring events, add additional challenge when responding to flaring events. Other causes of temporary flaring include non-scheduled maintenance or malfunction, planned maintenance, repair, or tests, and other issues such as weather or power outages. We determined based on the data and comments received on the proposal that establishing a cutoff at 24 hours or 48 hours is not supported because it necessarily fails to include a portion of the industry that is meaningful in this context. As such, we are finalizing an allowance to flare up to 72 hours for most situations, and are providing a mechanism to go beyond 72 hours to allow owners and operators the time they need to resolve equipment malfunction incidents and to include a backstop measure to ensure that temporary flaring does not continue after a malfunction incident is resolved.

In section III.A.3 of the January 2025 Proposal, the EPA acknowledged that rare instances may occur in which an owner or operator encounters a

[35] 90 FR 3734 (January 15, 2025).

[36] See 89 FR 16843–44 (March 8, 2024), section III.B.2.

malfunction, safety, repair, or maintenance event that requires routing to a flare or control device beyond the proposed 48-hour duration. To address such instances, the EPA solicited comments on specific situations that would be considered ''exigent circumstances.'' Based on comments received and a re-assessment of data provided to the EPA, we are finalizing an allowance to flare for greater than 72 hours if an exigent circumstance persists and there is a need to extend the temporary flaring duration for maintenance, safety issues, or repairs. While we expect that the vast majority of temporary flaring situations to be addressed within the 72-hour timeframe, we recognize that there may be equipment malfunction incidents that require more than 72 hours to resolve due to circumstances beyond an owner's or operator's control. However, to ensure flaring does not continue beyond the time that is necessary to resolve a malfunction incident, we are including a backstop to this extended timeframe of flaring until such equipment malfunctions during these exigent circumstances are resolved or no longer present, whichever is sooner.

After considering input from commenters, the EPA is finalizing that an ''exigent circumstance'' must be a situation that restricts an owner's or operator's ability to reasonably access a site with the necessary equipment and personnel to address and resolve equipment malfunction incidents that cause the need to temporarily flare associated gas for more than 72 hours. Reasonable site access is the ability of an owner or operator to safely transport the necessary personnel and equipment to a site experiencing an incident. Examples of possible situations that could limit site access include, but are not limited to, road washout from flooding; roads obstructed by snow, debris, or trees; and unsafe travel conditions from extreme weather, wildfires, and hazmat emergencies. Impediments to resolving equipment malfunctions also include when an owner or operator is unable to secure the required equipment to resolve an equipment malfunction incident due to reasons beyond an owner's or operator's control (*i.e.,* supply chain issues), or where there is a temporary shortage of personnel due to reasons beyond an owner's or operator's control (*e.g.,* a national pandemic). Examples of possible situations that could limit an owner's or operator's ability to secure required equipment to resolve an unexpected malfunction due to reasons beyond an owner's or operator's control include equipment transportation disruptions, trade disputes, equipment demand competition or national supply chain issues that cause major delays in securing parts or even render them unavailable for extended periods of time.

Not all situations that result in the need for temporary flaring qualify as exigent circumstances. Put another way, not all situations that result in the need to temporary flare will qualify as exigent circumstances. For example, inclement weather that results in equipment failures at a site, such as gas line freezing and power outages, would generally not constitute an exigent circumstance weather event if access to the site is not disrupted and equipment and personnel to resolve equipment malfunctions or failures are available.

Once the site is accessible and necessary equipment and personnel are available to resolve an equipment malfunction, flaring can continue until the malfunction is resolved. However, this must be no longer than 72 hours after the site is accessible, and the necessary equipment and personnel are available to resolve an equipment malfunction. The exigent circumstances provisions in the final rule are intended to accommodate rare instances where an owner or operator needs more than 72 hours to return the site to normal operations due to legitimate unforeseen circumstances outside of their control. The EPA does not expect that owners and operators will utilize these provisions often, and these provisions are not intended to allow for indefinite or long-term flaring. As always, the EPA may bring an enforcement action against an owner or operator whose actions do not comport with applicable regulatory provisions.

Lastly, the EPA is finalizing recordkeeping and reporting requirements when exigent circumstances are invoked. The EPA anticipates that exigent circumstances will be invoked only in limited cases, and that these additional recordkeeping and reporting requirements will not add undue burden to owners and operators. If an owner or operator claims that an exigent circumstance occurred and utilizes the extended temporary flaring timeframe, the owner or operator must maintain records that include: a written description of the ''exigent circumstance'' requiring the need to flare or route to a control device beyond 72 hours; a description of steps taken to resolve the need for temporary flaring/routing to a control device; the dates and times an identified ''exigent circumstance'' started and ended (*e.g.,* when owners or operators are able to access site, when personnel and/or equipment are available) and the total duration of each ''exigent circumstance''; and the dates and times temporary flaring/routing to a control device started and ended and the total duration of temporary flaring/routing to a control device due to the identified ''exigent circumstance.'' We require owners and operators to report this information in their annual report. Owners and operators are already required to complete recordkeeping and reporting for temporary flaring events and the additional recordkeeping and reporting requirements that would result from the extension of flaring duration beyond the temporary flaring limit for exigent circumstances should not impose any additional undue burden on the industry.

B. Vent Gas NHV Continuous Monitoring Requirements and Alternative Performance Test (Sampling Demonstration) Option for Flares and Enclosed Combustion Devices

The EPA finalized compliance requirements for continuous monitoring and initial and periodic performance testing for flares and enclosed combustion device(s) (ECDs) in the March 2024 Final Rule. Of relevance here are the requirements for those two control devices regarding the NHV monitoring requirements and alternative performance test (sampling demonstration) option. In the March 2024 Final Rule, with exceptions for catalytic vapor incinerators, boilers and process heaters, and enclosed combustors where temperature is an indicator of destruction efficiency, all flares and ECD must maintain the NHV of the gas sent to it above a minimum NHV if the control device is pressure-assisted or uses no assist gas.[37] [38] If an

[37] NHV is the potential energy available in a fuel sample, which is an indicator of flare performance and combustion efficiency. More specifically, it is the total energy released when a substance undergoes complete combustion with oxygen under standard conditions (*i.e.,* the amount of heat released when gas is burned). See *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations/frequently-asked-questions-control-devices#nhv.*

[38] In NSPS OOOOb and EG OOOOc, NHV is typically expressed in units of Btus per standard cubic feet (scf). In the March 2024 Final Rule, NHV monitoring is used to determine the Btu content of a gas stream which indicates whether a control device (*i.e.,* a flare or an ECD) is reaching the required efficiency by combusting at least 95 percent of the pollutants of concern (*i.e.,* methane and/or VOC). The March 2024 Final Rule requires that an NHV value must be at or above a certain Btu/scf threshold, depending on the design of the flare or ECD. An NHV value below the prescribed applicable minimum NHV value can be an indicator of reduced control device performance and efficiency at less than an acceptable level.

owner or operator uses a steam- or air-assisted flare or flare, the owner or operator must maintain the combustion zone NHV (NHV_{cz}) above a minimum level. If the owner or operator uses a perimeter assist air ECD or flare, the owner or operator must maintain the NHV dilution parameter (NHV_{dil}) above a minimum level. The NHV_{cz} and NHV_{dil} parameter terms account for the reduction in heating value caused by the introduction of air and/or steam. These terms were intended to ensure that the assist gas does not overwhelm the heating value provided by the vent gas to the point where proper combustion does not occur. Owners or operators also have the option to apply an alternative test method that either demonstrates continuous compliance with the combustion efficiency limit or directly demonstrates continuous compliance with the NHV_{cz} operating limit and, if applicable, the NHV_{dil} operating limit.

Associated gas from a well site affected facility was exempt from NHV monitoring (*i.e.,* assumed to always have high NHV) under the March 2024 Final Rule. Also under the March 2024 Final Rule, for each flare and ECD used to control gases other than associated gas from a well site affected facility, the owner or operator must conduct continuous monitoring using a calorimeter, gas chromatograph (GC), or mass spectrometer (MS) in order to determine the NHV of the vent stream.[39] As an alternative to continuous monitoring of NHV, the March 2024 Final Rule allows the owner or operator to conduct a performance test to demonstrate the NHV of the vent stream that consistently exceeds the applicable NHV operating limit in one of two ways: continuous sampling for 14 consecutive days plus ongoing (three samples every five years), or manual sampling (twice daily for 14 consecutive days) plus ongoing (three samples every five years) sampling.[40] The March 2024 Final Rule requires a minimum collection time of at least one hour for each individual manually collected sample. If inlet gas flow is intermittent such that collecting 28 samples in 14 days is infeasible, an owner or operator must continue to collect samples beyond 14 days in order to collect a minimum of 28 samples.

Owners or operators also have the option to use an alternative test method that demonstrates continuous compliance with the combustion efficiency limit.[41 42] If there are no values of the combustion efficiency measured by the alternative test method over the 14-day period that are less than 95 percent, the gas stream is considered to consistently exceed the applicable NHV operating limit and the owner or operator is not required to continuously monitor or conduct sampling of the NHV of the inlet gas to the flare or ECD.[43] Under the March 2024 Final Rule, owners or operators of steam- and air-assisted flares and ECD also must monitor the vent gas and assist gas flow rates and calculate NHV_{cz} and NHV_{dil} in accordance with the provisions in 40 CFR 63.670 (*i.e.,* the refinery maximum achievable control technology (MACT) rule, or ''Refinery MACT'' as codified in 40 CFR 63, National Emission Standards for Hazardous Air Pollutants (NESHAP) subpart CC). Alternatively, owners or operators of air-assisted flares may provide a one-time demonstration based on maximum air assist rates, minimum waste gas flow rates (based on backpressure regulator setting), and minimum NHV from the most recent sampling rather than continuously monitor vent gas and assist gas flow rates.[44]

In this Final Rule, the EPA is revising numerous aspects of the NHV monitoring and testing provisions in the March 2024 Final Rule. The EPA presented the rationale for these revisions in section III.B of the preamble of the January 2025 Proposal, with additional details provided in section IV.B of this preamble.

The EPA is expanding the gas streams that are exempt from monitoring due to high NHV content to include all flare and ECD for both new and existing sources. However, the EPA is also requiring that NHV monitoring be performed (via either continuous monitoring or the alternative performance test (sampling demonstration) option currently prescribed in the NSPS OOOOb and EG OOOOc regulations) in cases where inert gases are added and for other miscellaneous scenarios which decrease the NHV content of the inlet stream gas to all flare and ECD for both new and existing sources.[45] Examples of these known operational scenarios include combining acid gas removal (AGR) system amine regenerator still column vent gas with affected facility vent gas, combining glycol dehydration unit reboiler vent gas with affected facility vent gas streams without water removal, high water content in vent streams from certain storage vessels, and enhanced oil recovery (EOR) sites in fields using water or carbon dioxide (CO_2) flooding. The EPA is finalizing recordkeeping and reporting requirements to specifically indicate whether the flare or ECD receives (or does not receive) inert gases (inerts) or other streams which may lower the NHV of the combined stream, and, if so, a description of the operating scenario(s) which may lower the NHV of the combined stream through the introduction of those inert gases or other streams.

The EPA is also finalizing, as proposed, to replace the general exemption from NHV monitoring for associated gas for any control device used at ''well site affected facilities'' with NHV monitoring that is more reflective of industry operations, in order to be consistent with the overall NHV monitoring requirements for all affected OOOOb and OOOOc sources.[46]

In addition, when an owner or operator chooses to meet the NHV compliance demonstration by conducting the alternative performance test via the NHV grab sampling option, the EPA is finalizing, as proposed, a clarification that sampling may be conducted upstream of the inlet to the control device, provided that the sample is representative of the gas inlet to the

[39] 89 FR 16820 (March 8, 2024).

[40] See 40 CFR 60.5417b(d)(8)(iii)(A) and 40 CFR 60.5417b(d)(8)(iii)(G) for NSPS OOOOb sources and 40 CFR 60.5417c(d)(8)(iii)(A) and 40 CFR 60.5417c(d)(8)(iii)(G) for EG OOOOc sources.

[41] Under the provisions outlined in 40 CFR 60.5412b(d) and 60.5415b(f)(1)(xi), sources can request to use an ''equivalent method'' pursuant to 40 CFR 60.8(b)(2), or ''an alternative method the results of which [the Administrator] has determined to be adequate for indicating whether a specific source is in compliance'' pursuant to 40 CFR 60.8(b)(3). The EPA is currently accepting and reviewing applications for alternative (ALT) test methods for NHV monitoring in the oil and natural gas sector. See *https://www.epa.gov/emc/oil-and-gas-alternative-test-methods#:~:text=The%20application%20portal%20can%20be,Air%20Emission%20Measurement%20Center%20webpage.* Since the March 2024 Final Rule's publication, two alternative test method requests have been approved by the EPA for use under NSPS subpart OOOOb: (1) ALT–156 Alternative Test Method to monitor the NHV of the flare combustion zone at facilities subject to NSPS OOOOb and (2) ALT–157 Alternative Test Method for determining NHV from gas sent to an ECD or Flare subject to NSPS OOOOb. A list of the EPA's approved alternative test methods can be found at *https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods.*

[42] Per 40 CFR 60.8(b)(5), the EPA has more general authority to approve alternative test methods involving ''shorter sampling times and smaller sample volumes when necessitated by process variables or other factors.''

[43] See 40 CFR 60.5417b(d)(8)(iii)(D) and 40 CFR 60.5417c(d)(8)(iii)(D).

[44] See 40 CFR 63.670(j)(6).

[45] For the purposes of the NHV compliance provisions, inert gases (or ''inerts'') are gases that do not readily undergo combustion. Inert gases consist of or contain high concentrations of nitrogen, CO_2, water, or other compounds that have a net heating value of zero. *See* 90 FR 3742 (January 15, 2025).

[46] 90 FR 3746 (January 15, 2025).

control device. For example, sampling may be conducted from a location on the control device piping header, provided the sampling location is downstream of all waste gas inlets into the header.

The EPA is finalizing, as proposed, a clarification that the NHV of the vent stream must be determined in British thermal units per standard cubic feet (Btu/scf), where standard conditions are 20 degrees Celsius (°C), not British thermal units per pound (Btu/lb). If the composition is determined in weight percent, those concentrations can be used, but they will need to be converted to volume percent (equivalent to mole percent) based on the molecular weight of the constituents.

The EPA is also finalizing, as proposed, that the 14-day period for the performance test (sampling demonstration) option must be consecutive operating days, while also allowing for breaks in performance testing over weekends and holidays which may occur during the 14-day sampling period, provided that no sampling day is spaced more than 3 operating days apart from the previous sampling day.[47 48]

In addition, the EPA is specifying that for the purposes of determining the hourly average for continuous samples, the average shall be a block hourly average.[49] The EPA is not amending the sampling frequency (*i.e.,* two samples per day for 14 days with an ongoing demonstration of three samples every five years) for the performance test (sampling demonstration) option for either NSPS OOOOb or EG OOOOc.

The EPA is also retaining the one-hour minimum sampling time for the twice daily samples, except in cases where low or intermittent flow makes one-hour sampling infeasible for both NSPS OOOOb and EG OOOOc sources. In such a case, the EPA is allowing less than one-hour sampling times, provided that the sampling time used and the reason for the reduced sampling time is documented and reported.

The EPA is finalizing, as proposed, a clarification in both NSPS OOOOb and EG OOOOc to more clearly allow the use of the sampling methodology alternative to the continuous monitoring in 40 CFR 60.5417b(d)(8)(iii) for all types of air- and steam-assisted flares or ECD.

Finally, for NSPS OOOOb, the EPA is retaining the NHV_{cz} and NHV_{dil} monitoring requirements but more clearly including the provisions at 40 CFR 60.5417b(d)(8)(vi) to allow for the use of approved alternative test methods as provided in 40 CFR 60.5412b(d)(1)(i) and (ii) for continuous monitoring of NHV_{cz} and, if applicable, NHV_{dil}. We are also finalizing, as proposed, a clarification in 40 CFR 60.5417b(d)(8)(iv) regarding when flare flow or assist rates are not required to be monitored. In addition, as proposed, for EG OOOOc, the EPA is removing the requirement to comply with and conduct monitoring for NHV_{cz} and NHV_{dil} for air- and steam-assisted flares and ECD used for existing sources. This series of revisions in EG OOOOc includes changes in the initial compliance requirements for air- or steam-assisted flares or ECD in 40 CFR 60.5412c, the continuous compliance requirements for these control devices in 40 CFR 60.5415c, and the continuous monitoring requirements for these control devices in 40 CFR 60.5417c. We are also finalizing, under EG OOOOc, that air- or steam-assisted or flares or ECD must meet an increase in the minimum NHV in the vent gas from 270 to 300 Btu/scf.

C. Correction of Inadvertent Deletion of Regulatory Text

As discussed above, in the July 2025 IFR, the EPA amended certain compliance deadlines and timeframes for implementation in response to information received after promulgation of the 2024 Final Rule to address significant concerns that certain regulatory provisions in the March 2024 Final Rule were not workable or contained problematic regulatory language that prevented compliance. On December 3, 2025, the EPA published a final rule that included discrete changes to specific regulatory text within 40 CFR part 60 subpart OOOOb (December 2025 Final Rule).[50] Specifically, the EPA finalized amendments to the compliance deadline for NHV monitoring and provided additional time for the submission of initial annual reports at 40 CFR 60.5420b(b). The amendatory instructions for the final rule inadvertently amended all of 40 CFR 60.5420b(b) paragraph (b) in lieu of just the introductory text for paragraph (b), as intended. This resulted in the erroneous deletion of paragraphs 40 CFR 60.5420b(b)(1) through (15), which was neither intended nor proposed.

To correct this inadvertent error, the EPA is finalizing a technical correction to reinstate regulatory text for the reporting requirements in 40 CFR 60.5420b(b)(1) through (15). The substance of the December 2025 Final Rule remains unchanged by reinstating this erroneously-deleted regulatory text. Section 553(b)(B) of the Administrative Procedure Act, 5 U.S.C. 553(b)(B), provides that, when an agency for good cause finds that public notice and comment procedures are impracticable, unnecessary, or contrary to the public interest, the agency may issue a rule without providing notice and an opportunity for public comment. The EPA has determined that there is good cause for making this technical correction final without prior proposal. Such notice and opportunity for comment is unnecessary, as this technical correction restores the unintentional deletion of regulatory text made by the regulatory revisions associated with the December 2025 Final Rule.

The application of the APA's ''good cause'' exemption in this final rule is limited to correcting the inadvertent deletion of 40 CFR 60.5420b(b)(1) through (15) and does not extend to any other portion of this final rule. Further, by correcting this unintentional error, EPA is not reopening any issues from the December 2025 Final Rule or the associated IFR from July of 2025.

IV. Significant Comments and Changes Since Proposal for NSPS OOOOb and EG OOOOc (January 2025 Proposal)

This section of the preamble presents in each subsection a detailed summary of the significant comments received on, and changes made, since the January 2025 Proposal for the topic addressed in that subsection. This final action does not address or take any position on the best system of emission reduction (BSER) analysis included in the March 2024 Final Rule record which the EPA used to support promulgation of the standards included in NSPS OOOOb and the presumptive standards included in EG OOOOc.

[47] In this context, an ''operating day'' is considered a normal business day of operation (*i.e.,* Monday–Friday), and weekends and holidays are considered calendar days, but not ''operating days.''

[48] However, if the affected source is operating during a given weekend or holiday, the facility may elect to either sample or not sample during the weekend or holiday.

[49] Each block average value for each 1-hour period (or shorter periods) are to be calculated from all measured data during each period. If the inlet stream is continuously sampled for 14 days, the hourly block average will be determined on a noon to 1 p.m., 1 p.m. to 2 p.m., etc. basis.

[50] 90 FR 55671 (December 3, 2025).

The EPA's full response to comments on the January 2025 Proposal, including any comments not discussed in this preamble, is available in the EPA's Response to Comment (RTC) document for this final rule.[51]

A. Temporary Flaring Provisions for Associated Gas in Certain Situations

For oil wells that are not routinely flaring (*i.e.,* wells that route associated gas to sales lines or an equivalent alternative), the March 2024 Final Rule allowed owners and operators to route associated gas to a flare or control device in certain situations for 24 hours. These situations include times when there is a need to flare due to malfunctions, including for safety reasons. Further, these situations may include repair, maintenance (including blowdowns), bradenhead test, packer leakage test, production test, or commissioning. As stated in the January 2025 Proposal, industry petitioners seeking reconsideration claimed that the 24-hour limitation for temporary flaring is not sufficient for malfunctions, including for reasons of safety, and/or for repair and maintenance. Additionally, they claimed well sites may not be accessible during weather events (*i.e.,* winter storms), which are a significant factor for temporary flaring that lasts for more than 24 hours. Industry petitioners maintained that a 72-hour timeframe is more appropriate for temporary flaring due to the unique characteristics of each wellsite, weather conditions, or a combination of both. In the January 2025 Proposal, the EPA proposed to allow 48 hours for temporary flaring based on submitted industry data. The EPA agreed that the data showed that 24 hours was insufficient to resolve all malfunction, maintenance, and repair events. In the January 2025 proposal, the EPA also solicited comments on allowing owners and operators of associated gas affected facilities to route to a flare or control device for up to 72 hours if exigent circumstances exist, since the industry indicated that some events last for more than 48 hours. In particular, the EPA solicited comments on whether there are other specific exigent circumstances for which the EPA should consider allowing an owner or operator to route to a flare or control device beyond the proposed 48-hour allowance for repairs and malfunctions. Furthermore, the EPA solicited comments on recordkeeping and reporting requirements if the EPA were to include an allowance for owners or operators of associated gas affected facilities to route to a flare or control device for up to 72 hours for exigent circumstances.

The EPA received several comments on this aspect of the January 2025 Proposal. The EPA received comments on exigent circumstances, the temporary flaring timeframe, and recordkeeping and reporting requirements. These comments and the EPA's responses are provided in sections IV.A.1 through 4 of this preamble. The EPA also received comments requesting alternative exemptions and cutoffs to limit temporary flaring. These comments and the EPA's responses are provided in section IV.A.5 of this preamble. The EPA's full response to comments on the January 2025 Proposal, including any comments not discussed in this preamble, is available in the EPA's RTC document for the final rule.

1. Exigent Circumstances

In the January 2025 Proposal, the EPA solicited comment on allowing owners or operators of associated gas affected facilities to temporarily route the associated gas to a flare or control device for up to 72 hours in certain situations if exigent circumstances exist. Such exigent circumstances would include situations where an owner or operator cannot physically access a site due to weather or other conditions (*e.g.,* road closures). In addition to extreme weather events and road closures, the EPA solicited comment on whether there are other specific exigent circumstances for which the EPA should consider allowing an owner or operator to route to a flare or control device beyond the proposed 48-hour allowance for repairs and malfunctions. The EPA received several comments on this aspect of the January 2025 Proposal. These comments and the EPA responses are provided in this section of the preamble.

Comment: Several commenters requested that the EPA include other exigent circumstances in addition to those proposed. One commenter requested that the EPA clarify that exigent circumstances include, but are not limited to, flooding, road washouts, fires and explosions, personnel shortages due to illness or labor disputes, wildfires, earthquakes, hazmat emergencies, evacuation orders, war or civil unrest, and equipment supply chain issues.[52]

Another commenter[53] noted that, as stated in previous comments they submitted on the December 2022 Supplemental Proposal,[54] it is often necessary to temporarily route gas to control devices for safety and/or operational purposes in situations when associated gas could not be routed to a sales line or used for other beneficial purposes. The commenter requested that the EPA provide additional flexibility to allow temporary routing of gas to control devices when other exigent circumstances exist, including, but not limited to, interruption in service, extreme weather events, and road closures that prevent access to sites. The commenter stated that the January 2025 Proposal cites an API survey that concluded the average duration for temporary flaring was 46 hours per event. While the changes in the January 2025 Proposal to allow temporary flaring from 24 to 48 hours might accommodate the average temporary flaring event determined in the study, the commenter urged the EPA to consider allowing temporary flaring of 72 hours or more to account for the varying configurations of well sites and exigent circumstances.

Consistent with the previous comment, another commenter noted that the EPA requested input on other exigent circumstances that warrant flaring beyond 48 hours.[55] The commenter listed inclement weather, site access, operations outside normal business hours, availability of service providers and equipment, safety of operator personnel or the public, and repair, maintenance, production testing, or commissioning as exigent circumstances warranting longer flaring times. However, the commenter recommended that the EPA allow other scenarios when 72 hours of flaring would result in lower emissions than the alternative, *e.g.,* shutting down a facility requiring blowdowns that vent emissions to the atmosphere resulting in greater emissions as compared to those from flaring. As such, the commenter requested that the EPA consider all exigent circumstances to include situations where the alternative operation would result in more emissions, rather than allowing flaring for 72 hours.

Response: As noted in section III.A.4 of the January 2025 Proposal (Basis for Proposed Changes), the EPA acknowledges that there are special

[51] Reconsideration of Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review: Response to Public Comments on the January 2025 Proposed Rule (90 FR 3734; January 15, 2025). Included in Docket ID EPA–HQ–OAR–2024–0358.

[52] Document ID No. EPA–HQ–OAR–2024–0358–0082.

[53] Document ID No. EPA–HQ–OAR–2024–0358–0085.

[54] Docket ID No. EPA–HQ–OAR–2021–0317.

[55] Document ID No. EPA–HQ–OAR–2024–0358–0095.

situations where a longer timeframe than proposed may be needed and such circumstances may be beyond the owner's and operator's control. While the EPA agrees with some commenters that other exigent circumstances should be included in addition to extreme weather events and road closures, not every situation suggested by commenters qualifies as an exigent circumstance. As explained in section III.A of this preamble, the events that qualify for the exigent circumstances extension should be severe in nature and have a direct impact on the owner's or operator's ability to physically access the site with the necessary equipment and personnel to address the equipment malfunction incident which caused the need to temporarily flare. For instances where there is a need to flare beyond 72 hours due to an unexpected malfunction event and equipment and/or personnel are not readily available due to supply chain issues and/or temporary personnel shortages due to reasons beyond an owner's or operator's control, the EPA agrees that allowing an owner or operator to flare beyond 72 hours meets EPA's intent of what is considered an ''exigent circumstance'' and we revised the final rule to specifically allow flaring beyond 72 hours for such instances. While the EPA acknowledges that there may be instances when extraordinary circumstances, such as a national pandemic which is beyond an owner's or operator's control, could result in a temporary shortage of personnel being available to resolve an unexpected malfunction or to access a facility within 72 hours of an event, we do not consider personnel shortages due to illness or labor disputes to qualify as exigent circumstances. Personnel shortages due to illness or labor disputes are best characterized as an internal operational matter for which the owner or operator holds primary responsibility and is expected to manage through appropriate contingency planning.

To address commenters' concerns, the final rule defines an ''exigent circumstance'' to be a situation that results in the inability to reasonably access a site with the necessary equipment and personnel to address and resolve incidents that cause the need to temporarily flare associated gas for more than 72 hours. This includes circumstances where there is a need to flare beyond 72 hours due to an unexpected malfunction event and equipment needed to resolve an incident are not readily available due to an owner's or operator's inability to secure the required equipment for reasons beyond an owner's or operator's control (*i.e.,* supply chain issues); or there is a temporary shortage of personnel needed to resolve an incident due to a circumstance such as a declared national pandemic that is beyond an owner's or operator's control.

To address a commenter's request that we allow flaring for exigent circumstances to include situations where an alternative operation would result in more emissions rather than allowing flaring for 72 hours, we revised the final rule to allow flaring for up to 72 hours and beyond 72 hours for exigent circumstances, reducing the need for well shut ins.

In this final action, we are revising the March 2024 Final Rule to allow temporary flaring of associated gas for up to 72 hours for situations where the owner or operator cannot comply with the standard due to malfunctions, including reasons for safety, repairs, and maintenance. For exigent circumstances, an owner or operator can temporarily route to a flare or control device for durations over 72 hours until an exigent circumstance is no longer present. Following the new temporary flaring timeframe extension and clarification of what constitutes an exigent circumstance as stated in section III.A of this preamble, we disagree that some of the events listed by commenters (operations outside normal business hours, availability of service or equipment, safety of the operator or the public, and activities like repair, maintenance, production testing, or commissioning) on their own qualify as exigent circumstances. In these instances, an owner or operator will have up to 72 hours to resolve equipment malfunctions, which is in line with what the commenter requested. However, we also acknowledge that some of these situations may fall under an exigent circumstance if the necessary equipment and personnel are not available to resolve a malfunction incident within a 72 hour timeframe due to circumstances that are beyond an owner's or operator's control, or access to a site is restricted due to worker safety (*e.g.,* if traveling to the site is unreasonably dangerous due to a wildfire). After invoking exigent circumstances, flaring can continue until the equipment malfunction incident is resolved. However, this must be no longer than 72 hours after the site can be accessed, and the necessary equipment and personnel are obtained (72 hours after the exigent circumstances which prevented access and equipment malfunction repair are no longer present).

2. Allowance for Temporary Flaring of 72 Hours or More

In the January 2025 Proposal, the EPA proposed extending the allowable time for temporary flaring of associated gas during malfunctions, including for reasons of safety and during repair and maintenance. The proposed allowable timeframe was 48 hours, an increase from 24 hours in the March 2024 Final Rule. In response, several commenters requested that the EPA further extend the temporary flaring allowance to 72 hours. These commenters argued that a longer duration would better reflect field conditions, particularly in areas where access to equipment or personnel is delayed due to weather, geography, or other logistical barriers. They stated that even with proactive planning, certain malfunctions or maintenance activities may require more than 48 hours to resolve. The commenters also noted that forcing operators to end flaring before the issue is resolved could create safety risks or lead to unnecessary equipment shutdowns.

Other commenters disagreed and urged the EPA to retain the original 24-hour limit or allow for extensions only when operators clearly justify the need based on specific facts. They expressed concern that a blanket 72-hour window could weaken enforcement and lead to longer periods of uncontrolled emissions. They emphasized the need for clear limits to ensure that temporary flaring remains a last resort and is used only when necessary. The API data submitted to the EPA along with information from other stakeholders [56] show a range of flaring durations, with a notable percentage of events exceeding both 24 and 72 hours. These data suggest that while an extended flaring duration is not the norm, it does occur with some regularity, especially in cases involving equipment failure, inclement weather conditions and/or limited site access. Several comments were received on this aspect of the January 2025 Proposal. These comments and EPA's responses are provided in this section of the preamble.

Comment: One commenter [57] appreciated the EPA's acknowledgment that a 24-hour limit on temporary flaring during situations they describe as ''Critical Circumstances'' (*e.g.,* due to a malfunction or incident that endangers the safety of operator personnel or the public or during repair and maintenance

[56] Docket ID No. EPA–HQ–OAR–2024–0358.

[57] Document ID No. EPA–HQ–OAR–2024–0358–0092.

activities) is often infeasible and warrants additional time, particularly for remote, unmanned sites in areas prone to extreme weather events and poor road conditions.[58] However, they expressed that they do not believe that the proposed 48-hour allowance will allow sufficient time to fix the problem and return the site to normal operations such that temporary flaring can stop during many ''critical circumstances.'' The commenter suggested that a 72-hour temporary flaring duration would provide sufficient time to respond to, troubleshoot, and repair equipment during most, but not all, ''critical circumstances'' in areas where extreme weather and road conditions are frequent, such as during the winter months in North Dakota.[59] Further, the commenter added that these repairs are often dangerous to undertake due to the extreme weather in, for example, North Dakota's Williston Basin. For instance, the commenter reported that on February 10th, 2025, the National Weather Service issued an Extreme Cold Warning in the majority of counties in North Dakota, advising that ''life threatening wind chills as low as 55 below zero could cause frostbite on exposed skin in as little as 5 minutes.'' [60] The National Weather Service also advised to take precautions ''if you must go outside.'' [61] The commenter stated that requiring operators to undertake immediate repair work in these conditions can unnecessarily put them in harm's way. For those ''critical circumstances'' that would otherwise require longer than 72 hours, the commenter noted that operators ''must innovate and improve their maintenance, response, and repair practices to meet what would remain a challenging deadline in many instances.''

The same commenter provided that, in the January 2025 Proposal, the EPA cited survey data provided by API (the ''Temporary Flaring Survey'') to support extending the temporary flaring allowance up to 48 hours.[62] The EPA proposed extending the temporary flaring allowance from 24 to 48 hours in the January 2025 Proposal based on the Temporary Flaring Survey's average flaring duration time of 46 hours. In doing so, the commenter asserted that the EPA ignored that the data shows the average flaring duration is not uniform across basins. According to the commenter, both the Temporary Flaring Survey and the commenter's own data [63] demonstrate that the widely dispersed facilities and extreme winter weather conditions in the Williston Basin (North Dakota and Montana) can necessitate longer temporary flaring for responding to ''Critical Circumstances'' other than warmer and more easily accessed basins, like the Permian Basin (Texas and New Mexico). They highlighted that the Temporary Flaring Survey data shows that Williston Basin flaring incidents exceeded 72 hours in 78 percent of the reported data, compared to just 11 percent in the Permian Basin.[64] For the Permian Basin, they highlighted that 12 percent of flaring events exceeded 24 hours, claiming that where flaring exceeded 24 hours, it is extremely probable the flaring continued beyond 72 hours. The commenter reported that its extensive temporary flaring data (*e.g.,* Temporary Flaring Survey) shows that an average of approximately 72 hours of temporary flaring is necessary during their ''Critical Circumstances.'' The commenter asserted that the data and information provided by both API and Hess suggest that a 72-hour temporary flaring duration allowance is an appropriate default for a nationwide rule.[65]

The commenter added that it provided temporary flaring data that reflected events that it had identified internally as the highest priority of work (''break-in work'').[66] The commenter explained that this is the priority given to ''Critical Circumstance'' responses. The commenter added that its sites are often not accessible within 24 hours due to difficult terrain, long travel distances between facilities, and extreme weather. These conditions are an impediment to the first step in response: travelling to the facility to investigate the cause of the ''Critical Circumstance.'' The commenter added that its data show the average response time from notification creation to resolution was slightly more than 72 hours; however, as an average implies, many events lasted longer than 72 hours. The commenter contended that its data demonstrate that 48 hours is often not long enough to travel to the facility, troubleshoot, obtain necessary equipment, and complete repair, even with normal business processes that incorporate efficiencies.[67] The commenter asserted that the EPA's proposed 48-hour limit inappropriately relied on a summary report from New Mexico and from a Colorado regulation to assert that a 48-hour period is sufficient for temporary flaring for malfunction/safety and repair/maintenance situations. However, the commenter noted that areas such as North Dakota are subject to more frequent and more extreme weather events than those areas.

In addition, the commenter explained that oil and gas facilities in North Dakota are spread across expansive and geographically remote locations.[68] The commenter expressed that it does not believe it is appropriate to finalize a one-size-fits-all approach based on these two unique States (*i.e.,* Colorado and New Mexico). Moreover, the commenter reiterated that the Permian Basin data in the Temporary Flaring Survey shows that where flaring exceeded 24 hours, it

[58] The EPA notes that while the commenter uses the term ''Critical Circumstances,'' we interpret this to mean ''exigent circumstances.''

[59] To date, Hess (the commenter) has provided the EPA with extensive documentation of circumstances affecting its Williston Basin production operations that necessitate up to 72-hours for temporary flaring in these circumstances. See November Hess Presentation; Hess Corporation, Hess Briefing for EPA: Oil and Natural Gas Final Methane Rule NSPS OOOOb and EG OOOOc, EPA–HQ–OAR–2024–0358–0020 (Feb. 29, 2024) (''February Hess Presentation''); Hess Corporation, Hess Briefing for EPA: NSPS OOOOb Safety, Malfunction & Repair Temporary Flaring Allowance, EPA–HQ–OAR–2024–0358–0031 (June 3, 2024) (''June Hess Presentation''); Hess Corporation, McKenzie County Frost Restrictions, EPA–HQ–OAR–2024–0358–0037 (July 19, 2024); Hess Corporation, Examples of North Dakota Road Closures and Restrictions, EPA–HQ–OAR–2024–0358–0037 (July 19, 2024); Hess Corporation, Hess E.O. 12866 Meeting with OMB/OIRA: Oil and Natural Gas NSPS OOOOb and EG OOOOc Reconsideration Proposal, 13, EPA–HQ–OAR–2024–0358–0038–0046 (Nov. 7, 2024) (''November Hess Presentation'').

[60] National Weather Service, NWS Alerts, *https://alerts.weather.gov/search?history=1&zone=NDZ009* (last visited Feb. 28, 2025).

[61] Id.

[62] See American Petroleum Institute, Operator Survey: Temporary Flaring, 4, EPA–HQ–OAR–2024–0358–0038 (July 2024) (''Temporary Flaring Survey'').

[63] Hess's operations in the Bakken formation span roughly 7,200 square miles and include many unmanned sites. Hess provided information demonstrating that it often cannot physically access a site within 48 hours, and seasonal conditions and extreme weather events may delay accessibility for days and up to over a week until access roads to a wellsite are passable. See November Hess Presentation at 10.

[64] Temporary Flaring Survey at 6.

[65] See Hess Corporation, Hess E.O. 12866 Meeting with OMB/OIRA: Oil and Natural Gas NSPS OOOOb and EG OOOOc Reconsideration Proposal, 13, EPA–HQ–OAR–2024–0358–0046 (Nov. 7, 2024) (''November Hess Presentation'').

[66] Hess's ''highest priority notifications'' response system prioritizes repair work that can result in temporary flaring above previously scheduled work. Hess provided the EPA with data showing that the average notification creation to resolution cycle times between 2020 and 2024 averaged 3.2 days. See June Hess Presentation at 12.

[67] Under Hess's ''highest priority notifications'' response system, it can still sometimes take up to 21 hours for an operator to access the facility and identify the problem necessitating the temporary flaring. If a maintenance crew is required for repair, it can take multiple days even with equipment available. See June Hess Presentation at 12.

[68] See Hess Corporation, Hess' Bakken Operating Area, EPA–HQ–OAR–2024–0358–0038–0037_attachment 1 (July 19, 2024).

is extremely probable that flaring exceeded 72 hours. In conclusion, the commenter argued that a blanket 72-hour temporary flaring allowance for ''Critical Circumstances'' provides a more reasonable timeframe and will force operator innovation.

Conversely, another commenter urged the EPA not to allow operators to temporarily route associated gas to a flare or control device for up to 72 hours for weather-related delays.[69] The commenter did not support any additional allowances for temporary flaring for up to 72 hours. In the commenter's opinion, the Temporary Flaring Survey does not support the need for a 72-hour allowance for weather-related delays. The commenter reported that only three percent of the total data demonstrated that inclement weather was the cause of needing time to mitigate flaring with an average duration of 21 hours of temporary flaring per event.

The commenter also pointed to the Temporary Flaring Survey data on reportable emission events from the 2021 winter storm Uri that impacted Texas.[70] The data includes all reportable emission events the Texas Commission on Environmental Quality (TCEQ) received from all industry sectors in the State. The commenter expressed that it is vital that the EPA examines this data in more detail before moving forward with any extension of temporary flaring duration based on weather. The commenter highlighted that the TCEQ dataset includes 328 emission events, but 78 percent of those events occurred at facilities that are not upstream oil and gas facilities and argued that those events are therefore not relevant to any decision to allow for extended flaring due to inclement weather.

Response: The EPA appreciates the information and insights provided by commenters and agrees overall with the recommendations for extending the temporary flaring allowance to 72 hours. We agree with the commenters that the proposed 48-hour temporary flaring limit, while directionally helpful, does not adequately address the logistical complexities present in the widely dispersed locations in the oil and gas industry. Allowing for up to 72 hours promotes administrability and equitable treatment among sites for the vast majority of flaring incidents discussed in this preamble, while also providing for emissions reductions in tandem with the requirement that sources stop flaring as soon as the qualifying incident is resolved. Compliance with these requirements will be reported to the EPA and enforced through a combination of new (finalized in this rule) and preexisting (from the 2024 rule) emissions-reporting obligations, and many facilities have an independent economic incentive to cease unnecessary flaring where the gas could otherwise be captured and sold.

The Temporary Flaring Survey indicates that more than 17 percent of flaring events required more than 24 hours of temporary flaring of associated gas per event, and more than 15 percent of flaring events required more than 72 hours of temporary flaring per event. The causes of these extended flaring durations were multifaceted and included inclement weather, primarily in the Williston Basin which routinely faces harsh winter weather conditions, and other factors such as the unique characteristics of each wellsite (unmanned, remote, and dispersed).

Critically, weather is not the only contributor to extended flaring events, as demonstrated in the dataset and comments provided by petitioners. Information gathered from industry meetings and the Temporary Flaring Survey indicate that these logistical challenges exist regardless of weather and are often intensified by routine operational hurdles such as scheduling contractor support, transporting heavy equipment, and adhering to internal safety procedures. Further analysis reveals the Temporary Flaring Survey reported 86 flaring events as weather-impacted events, and the survey classified over 600 flaring events as ''[u]nknown.'' While we do not know the cause of the need to flare for the over 600 flaring events in the Temporary Flaring Survey, maintaining a 24-hour, or even 48-hour, flaring timeframe based on the percentage of reported inclement weather-impacted events presents a narrow reading of the data and does not reflect the ''[u]nknown'' flaring events that exhibited the highest flaring durations and standard deviations. The commenter's argument centers on a narrow interpretation of weather-related flaring events that indicates that only three percent of total incidents in the Temporary Flaring Survey cite weather as the cause for the need to flare and that those averaged 21 hours per event.[71] While it is true that the Temporary Flaring Survey indicates that flaring events often can be resolved quickly, the data and information provided by industry also indicate that other factors can impact an owner's or operator's ability to limit the duration of flaring that are beyond their control. In instances where an owner or operator is able to limit the duration of flaring by addressing the cause of the need for flaring in a timely manner, an owner or operator is encouraged to limit the flaring duration to the maximum extent possible. The EPA is extending the flaring allowance based on the ability of an owner or operator to access their flaring event site and resolve the cause of the need to flare. As noted previously, while weather can be a contributing factor affecting access to a site, it is not the only potential reason limiting access to a site. As such, the EPA has extended the allowance to flare up to 72 hours in absence of an exigent circumstance and allows more than 72 hours in instances where an owner or operator makes a legitimate exigent circumstance claim that limits their ability to access and resolve the cause for a flaring event within 72 hours. This extended timeframe gives owners and operators enough time to travel to facilities (including geographically remote facilities), troubleshoot, obtain necessary equipment, and complete repairs. It also provides sufficient time to overcome many inclement weather situations. This extended timeframe, coupled with the ability to claim exigent circumstances for even more time, should limit or eliminate the need to shut-in operations in situations of temporary flaring for malfunction, safety, or maintenance.

Additionally, the Temporary Flaring Survey shows regional variation in flaring durations, as a commenter notes. For instance, 78 percent of flaring incidents in the Williston Basin exceeded 72 hours, compared to just 11 percent in the Permian Basin. This variation highlights that a rigid one-size-fits-all approach based exclusively on national averages, and which does not allow for any flexibility, does not account for critical differences in field conditions, wellsite uniqueness, or operational complexity. The data confirm that events where flaring exceeds 24 hours often continue well beyond 72 hours. As such, setting the upper limit at 72 hours with the possibility of additional time for exigent circumstances better aligns with field data, while still placing expectations on owners and operators to promptly resolve issues.

As explained in sections IV.A.4 (Support for a 24-hour Allowance for Temporary Flaring) and IV.A.5 (Consideration of Additional

[69] Document ID No. EPA–HQ–OAR–2024–0358–0096.

[70] See API, Document ID No. EPA–HQ–OAR–2024–0358–0038, attachment 6.

[71] Document ID No. EPA–HQ–OAR–2024–0358–0096.

Limitations and Targeted Exceptions to Temporary Flaring) of this preamble, the EPA considered but did not adopt several approaches raised by petitioners and public comments on the proposal, including a 24-hour or 48-hour flaring allowance and additional temporary flaring limits or targeted geographical exceptions.

3. Recordkeeping and Reporting

In the proposed rule, the EPA also solicited comment on the recordkeeping and reporting requirements if the Agency were to include an allowance for owners or operators of associated gas affected facilities to route to a flare or control device for up to 72 hours for ''exigent circumstances.'' [72] The topics of exigent circumstances and temporary flaring duration are discussed more in section IV.A.1 and IV.A.2 of this preamble respectively. Specifically, we solicited comment on requiring an owner or operator who must make use of the extended timeframe to maintain records that include a written description of the exigent circumstance, the rationale for the need to route to a flare or control device beyond the default allowable timeline, a description of the measures taken to minimize temporary flaring/routing to a control device, and the duration of temporary flaring/routing to a control device due to the identified exigent circumstance. Lastly, we solicited comment on requiring an owner or operator to include a summary of their exigent circumstance recorded events in their annual report.

The EPA received two groups of comments about recordkeeping and reporting requirements for exigent circumstances. Support for recordkeeping and reporting came from environmental groups, who argued that these requirements are important for accountability, ensuring the flaring event was an appropriate action, and encouraging owners and operators to limit flare durations. Industry commenters opposed this proposed requirement. They argued that extending recordkeeping and reporting requirements for exigent circumstances would not provide any environmental benefit and would not expedite the repair or maintenance process. Industry commenters further asserted that having additional recordkeeping and reporting provisions would add unnecessary burden to owners and operators at a time when they should prioritize resources to address the emergency or maintenance event.

Based on comments received and EPA's decision to broaden what constitutes an ''exigent circumstance'' to include instances where the necessary equipment and/or personnel are not available to conduct the necessary repairs for reasons beyond an owner's or operator's control, the EPA is finalizing the following recordkeeping and reporting requirements when an exigent circumstance is invoked: a written description of the ''exigent circumstance'' requiring the need to flare or route to a control device beyond 72 hours; a description of the steps taken to resolve the need for temporary flaring/routing to a control device; the dates and times an identified ''exigent circumstance'' started and ended (*e.g.,* when owners or operators are able to access site, when personnel and/or equipment are available) and the total duration of each ''exigent circumstance''; and the dates and times temporary flaring/routing to a control device started and ended and the total duration of temporary flaring/routing to a control device due to the identified ''exigent circumstance.'' We require owners and operators to report this information in their annual report. See section IV.A.1 of this preamble for comments received on exigent circumstances and EPA's response to those comments.

As mentioned above, we received several comments on this aspect of the January 2025 Proposal. These comments and the EPA responses are provided in this section of the preamble.

Comment: Several industry commenters did not support the EPA requiring records and reporting (in annual reports) of information regarding exigent circumstances necessitating temporary flaring beyond the default time allowance. One commenter [73] stated that operators should focus on resolving emergencies and/or maintenance issues that arise to reduce and/or remove the need to flare, instead of recordkeeping and reporting requirements that provide no environmental benefit.[74] Additionally, according to the commenter, such recordkeeping and reporting causes burden for the operator and the EPA. The commenter requested that the EPA implement a blanket timeframe of at least 72 hours for temporary flaring without the need for recordkeeping and reporting such events.

Similarly, one commenter [75] noted that the additional administrative recordkeeping and reporting burden to conduct, document, and report an exigent circumstance would not provide a corresponding environmental benefit.[76] The commenter stated that the NSPS OOOOb and EG OOOOc rules already require recordkeeping and reporting for temporary flaring events that are sufficient to provide transparency into operators' temporary associated gas flaring activities.

Another commenter expressed concern about the documentation required for exigent circumstances, stating that it is unnecessary and unduly burdensome as a blanket 72-hour allowance is warranted.[77]

Conversely, another commenter expressed that if the EPA finalizes a nationwide exception for exigent circumstances, then the EPA must add specific recordkeeping and reporting requirements to the rule.[78] The commenter supported the recordkeeping and reporting that the EPA listed in the proposal as a minimum requirement to document and justify any temporary flaring or routing to control devices that goes beyond the baseline limit. The commenter asked that this documentation include a description of the circumstance requiring extended flaring, the rationale for routing to a flare or control device beyond the allowed limit, documentation from public information that supports the claim that extended flaring was necessary (*e.g.,* traffic information showing road closures), a description of the measures taken to minimize temporary flaring, and the duration of temporary flaring. Also, the commenter requested that the annual report require a summary of the number, cause, and duration of extended flaring events.

Response: The EPA agrees that the near-term focus of owners and operators in these situations should be on the immediate need of resolving emergencies and/or maintenance issues as quickly as possible to mitigate the need to flare. However, we disagree that recordkeeping and reporting is unnecessary and that any such requirements will cause undue burden to the owners and operators. First, base-level recordkeeping and reporting requirements already exist for owners and operators in the regulations (40 CFR 60.5420b(b)(4)(i) and (2) and (c)(3) (i) and (ii); and 40 CFR 60.5420c(b)(3)(i) and (ii) and (c)(2)(i) and (ii)) for all temporary flaring that are not at issue in this rulemaking. Including exigent circumstance recordkeeping and

[72] 90 FR 3740–41 (January 15, 2025).

[74] Document ID No. EPA–HQ–OAR–2024–0358–0095.

[76] Document ID No. EPA–HQ–OAR–2024–0358–0092.

[77] Document ID No. EPA–HQ–OAR–2024–0358–0088.

[78] Document ID No. EPA–HQ–OAR–2024–0358–0096.

reporting only adds additional requirements when an exigent circumstance occurs. Thus, if the exigent circumstance provision is not invoked, owners and operators are not required to complete any additional recordkeeping and reporting beyond the base-level requirements for all temporary flaring situations. The additional information that we will collect for exigent circumstances does not duplicate the base-level recordkeeping requirements included in the March 2024 Final Rule and is not time-consuming or resource intensive.

Second, requiring additional recordkeeping and reporting for exigent circumstances documents compliance with the allowance for temporary flaring beyond 72 hours for exigent circumstances. Specifically, the additional recordkeeping and reporting requirements only apply when an owner or operator invokes an extension of flaring duration due to an exigent circumstance and only includes minimal documentation to ensure that owners and operators are properly invoking and implementing the flaring extension.

Lastly, in response to comments that claim that owners and operators should first focus on returning the site to normal operations, the EPA agrees. The recordkeeping requirements included in the final amendments can be completed after the owner or operator addresses the underlying issue that gave rise to the need for temporary flaring. None of the recordkeeping requirements mandate action contemporaneous with conducting repair or maintenance. The recordkeeping can occur after repair or maintenance but should happen relatively close in time so that the owner or operator can record accurate information.

4. Support for a 24-Hour Allowance for Temporary Flaring

Following the January 2025 Proposal, several industry representatives and State agency commenters recommended extending the temporary flaring allowance to 72 hours. In contrast, other commenters, including environmental organizations and private citizens, urged the EPA to retain the original 24-hour limit from the March 2024 Final Rule, with limited allowances for extensions up to 48 hours in exigent circumstances or until the event is resolved. As part of the proposed rule, the EPA requested data and feedback on whether the revised flaring duration could potentially increase primary or secondary emissions and invited additional information to either substantiate the proposed 48-hour allowance or justify maintaining the 24-hour duration in the March 2024 Final Rule.

The EPA received several comments on this aspect of the January 2025 Proposal. These comments and the EPA's responses are provided in this section of the preamble.

Comment: Two commenters requested that the EPA retain the 24-hour allowance for temporary flaring.[79] One commenter disagreed with the EPA's determination that the information provided in the Temporary Flaring Survey supports allowing temporary flaring for up to 48 hours during malfunctions but believes the information provided in the Temporary Flaring Survey supports retaining the 24-hour allowance, potentially with limited exceptions.[80] The commenter agreed with the EPA's statement that the Temporary Flaring Survey supports an expectation ''that owners and operators can feasibly limit temporary flaring to less than 24 hours in a large majority of situations.'' [81] The commenter stated that the Temporary Flaring Survey had 2,804 instances of temporary flaring of associated gas at sites in the San Joaquin, Permian, and Williston Basins.[82] According to the U.S. Energy Information Administration (EIA), the primary producers of associated gas in the U.S. are the Permian, Bakken, Eagle Ford, Anadarko, and Niobrara Basins.[83] The commenter observed that the Temporary Flaring Survey did not include any information on temporary flaring in the other three basins identified by the EIA. For the EPA to justify a nationwide change, the commenter contended that the agency should examine data from all basins where associated gas is primarily produced (and thus has the greatest potential for a need to temporarily route to a flare or control device) to determine whether the current allowance of 24 hours is appropriate. According to the commenter, the Temporary Flaring Survey does not support the EPA's proposed change to allow up to 48 hours for temporary flaring of associated gas, and data from other basins may also further demonstrate this change is not justified. The commenter asserted that the Temporary Flaring Survey therefore is not complete enough to justify an alteration of the standard for the entire country.

Additionally, the commenter stated that an analysis of the Temporary Flaring Survey shows the average duration of temporary flaring of associated gas is 46 hours, which the EPA used as the basis for its proposal. However, they reported that a detailed examination of this data does not support a blanket allowance of 48 hours.[84] The commenter noted that most of the data come from the Permian Basin (2,581, or 92 percent) and show that the average duration of temporary flaring was 26 hours, with 318 instances requiring greater than 24 hours (12 percent of the total instances for this basin). Nearly 75 percent of the instances (1,930) are labeled as ''high priority,'' and the average duration of temporary flaring for these events was five hours, with only 14 instances greater than 24 hours (0.7 percent). In the commenter's opinion, this demonstrates that operators can address issues, such as maintenance and safety concerns, leading to temporary flaring well within the currently allowed 24-hour duration for sites in the Permian Basin.

The commenter further observed that the 46-hour average duration in the Temporary Flaring Survey is skewed by data from the Williston Basin, representing only 166 total instances, or just six percent, of the Temporary Flaring Survey data. The commenter reported that the average duration of temporary flaring for these instances is 378 hours. Additional details provided by Hess, and within the Temporary Flaring Survey data, show that separator backpressure valve issues dominate as the cause of temporary flaring (89 percent of instances for the Williston Basin), and inclement weather is only listed as an issue for 10 instances, which have an average duration of 125 hours for temporary flaring. The commenter provided that additional information from Hess specifies these backpressure valve issues are unscheduled maintenance or malfunctions due to separator backpressure valve issues, but it is not clear whether these issues are preventable. The commenter asserted that this outlier data for the Willison Basin does not justify a blanket 48-hour nationwide allowance.

The commenter also noted that the Temporary Flaring Survey includes a total of 57 instances from the San Joaquin Basin, which is not one of the

[79] Document ID Nos. EPA–HQ–OAR–2024–0358–0080, EPA–HQ–OAR–2024–0358–0096.

[80] Document ID No. EPA–HQ–OAR–2024–0358–0096.

[81] 90 FR at 3740 (January 15, 2025).

[82] See API, Document ID. No. EPA–HQ–OAR–2024–0358–003, attachment 3.

[83] U.S. EIA, ''U.S. associated gas production increased nearly 8% in 2023.'' November 13, 2024. *https://www.eia.gov/todayinenergy/detail.php?id=63704#.*

[84] See Attachments A and B of the commenter's letter.

primary producers of associated gas. Moreover, the commenter indicated that the data for this basin demonstrate an ability to return to normal operations (*i.e.,* stop flaring of associated gas) after eight hours on average, with only four instances requiring more than 24 hours. The commenter pointed out that of those four instances exceeding 24 hours, three are labeled as ''high priority'' and the cause is listed as power failure (two instances), compressor failure (one instance), and valve failure (one instance). While these limited exceptions do exist, the commenter suggested that the overall data from the San Joaquin Basin further support the position that the EPA should retain the 24-hour allowance.

Also, the commenter evaluated data from New Mexico exploration and production operators, which the commenter claimed demonstrate that operators can comply with a 24-hour limit on temporary flaring during malfunctions or incidents that endanger the safety of operator personnel or the public, as well as during repair and maintenance activities.

The commenter argued that New Mexico requires exploration and production operators (''upstream operators'') to report flaring or venting of natural gas on form C–129 ''that exceeds 50 thousand cubic feet (MCF) in volume and either results from an emergency or malfunction, or lasts eight hours or more cumulatively within any 24-hour period from a single event.'' [85] The report must include the time of venting or flaring and the nature and cause of the venting or flaring.[86]

The commenter evaluated all C–129 reports filed with the New Mexico Oil Conservation Commission (OCC) between 2021 and 2025.[87] The commenter reported that the database contains reports filed by upstream and midstream operators. According to the commenter, of all the causes listed, 13 were identified that could be classified as a malfunction or incident that could endanger the safety of operator personnel or the public or as occurring during a repair or maintenance activities. The commenter listed in their comment letter the various causes for these events, including corrosion, downhole well maintenance, equipment failure, freeze, human error, lightning, liquids unloading, overflow-tank, pit, packer leakage test, power failure, repair and maintenance, production test, and commissioning to purge.

In its analysis of the New Mexico OCC dataset, the commenter stated that 99.7 percent of the total reported flaring incidents lasted 24 hours or less. According to the commenter, this data demonstrates that operators can comply with a 24-hour limit on flaring during malfunctions or incidents that endanger the safety of operator personnel or the public and also during repair and maintenance activities.[88]

Another commenter contended that the EPA's proposal to extend the temporary flaring allowance from 24 to 48 hours and include exigent circumstances to allow flaring up to 72 hours is a massive step in the wrong direction. The commenter contended that this policy, while trying to meet the demands of a changing industry, critically ignores the health and environmental implications that the commenter attributed to flaring. The commenter stated that instead of responding to concerns raised by oil and gas companies, thereby allowing what the commenter described as further damage to health and safety, there should be more focus on stricter regulations that veer toward alternative modes of energy production.

Response: For the reasons explained here, the EPA found comments suggesting that the EPA should retain the 24-hour allowance for temporary flaring of associated gas for malfunction, including for reasons of safety, and during all repairs and maintenance finalized in the March 2024 Final Rule to be unpersuasive.[89]

In finalizing the required timeframe for this provision, the EPA considered additional factors beyond the average flaring duration proposed in the January 2025 Proposal due to variabilities that exist in the industry at large.

Some commenters appear to suggest that a strict 24-hour limit on temporary flaring is warranted based on the claim that most events in the Temporary Flaring Survey, particularly in the Permian Basin, are resolved within that timeframe. However, this narrow interpretation of the data, when considered in the context of setting a national standard, ignores critical realities demonstrated across the full dataset and operational field conditions. First, while the Permian Basin represents a large portion of the data, flaring behavior and operational challenges do not appear to be uniform across the representative basins. Other regions, particularly the Williston Basin, face significantly harsher environmental conditions and logistical barriers that are not captured by simply focusing on Permian Basin averages. Commenters argue that because one region generally operates under favorable conditions, all other regions should be held to the same standard, an approach that is neither practical nor technically sound.

Additionally, commenters rely on averages without giving proper weight to variability. The same dataset across all responses shows that 17 percent of flaring events lasted longer than 24 hours, and 15 percent lasted longer than 72 hours—a meaningful minority that cannot simply be ignored. Averages can hide important outliers that matter operationally. For instance, the high standard deviation of 156 hours across the full dataset demonstrates that flaring durations vary dramatically and treating all events as if they should conform to an average disregards the complex, often unpredictable nature of these unique situations that may result in routing associated gas. Emergencies, severe weather, and mechanical failures in remote, unmanned sites frequently require more than 24 hours to troubleshoot, repair, and safely restore operations.

The EPA also disagrees with the claim that the datasets and other information available to the Agency are too limited to support a nationwide 72-hour flaring allowance. While the Temporary Flaring Survey does not include every basin, it contains 2,804 flaring events from several major oil and natural gas producing regions, providing a meaningful sample of real-world operations. Events exceeding both 24 and 72 hours occurred across different categories. For example, in the ''Other—specify'' category of the Temporary Flaring Survey, gas sales line freezing led o flaring durations as high as 117 hours, power outages resulted in delays up to 48 hours, and high hydrogen sulfide (H_2S) levels forced compressor shutdowns lasting 29 hours. In the C–129 reports filed with the New Mexico OCC that the commenter evaluated, while these events represent a small portion of the more than 28,000 total upstream incidents examined, there were still 127 flaring incidents lasting more than 24 hours and 103 incidents

[85] N.M. Admin. Code Section 19.15.27.8.G.(1)(a).

[86] Id. at Section 19.15.27.8.G.(1)(b).

[87] See Attachments C and D of the commenter's letter for the Excel workbooks that include their analysis.

[88] See Attachments C and D of the commenter's letter for the Excel workbooks that include their analysis.

[89] With respect to the portion of the comments suggesting that the EPA should ''veer toward alternative modes of energy production,'' the Agency first notes that such comments are out of scope for this action which concerns limited technical amendments to the temporary flaring provisions for associated gas and to NHV. Moreover, basing a regulation under Clean Air Act section 111 on a shift to ''alternative modes of energy production'' does not comport with caselaw. See *West Virginia* v. *EPA,* 597 U.S. 697 (2022).

lasting more than 72 hours during repair and maintenance activities. So, even the data from New Mexico shows that 24, or even 48, hours is not sufficient time in some instances. These examples show that extended flaring durations can result from malfunction or safety related issues that are not tied to any single region.

A national default limit of 72 hours is straightforward in terms of compliance, especially for operators who work in more than one basin. It gives enough time to fix most issues without needing to claim an exigent circumstance. It also avoids subjecting sources across different regions to unequal treatment, as well as avoiding situations where sources are subject to the conditions discussed above that may contribute to longer flaring incidents but are captured in the existing record or analysis. Such sources could be existing sources or new sources, and a nationwide standard for new sources obviated the need to continually analyze and adjust regional-based considerations. For rare cases that go beyond 72 hours, the rule allows limited flexibility as addressed in section IV.A.1 of this preamble. And, as discussed previously, the EPA is also requiring flaring to cease when the incident triggering flaring has been resolved, which serves as a protective backstop to reduce emissions notwithstanding the 72 hour allowance. We expect that incidents that previously have been resolved within 24 or 48 hours would continue to be resolved as quickly as practicable and that flaring would cease when the issue is resolved.

The EPA does not dispute the general idea that the data available to the Agency in this rulemaking docket demonstrate that many instances of temporary flaring of associated gas are resolved, with the site returning to normal operations, within 24 hours. However, we view this information within the context that these instances mostly occurred at sites that were not subject to 2024 final rule NSPS 24-hour limit at the time of the data collection. As such, owner and operators were already responding quickly to address repair, maintenance, and safety issues and returning their sites to normal operations (ceasing flaring) due to considerations outside the NSPS and EG. We have no reason to believe that those other considerations, whatever they may be (*e.g.,* State or local laws/regulations economic incentives to restore flow to sales lines), would vanish upon finalizing the amendments to increase the NSPS and EG timeline to 72 hours. We also have no reason to predict that allowing up to 72 hours, or more with exigent circumstances, in the NSPS and EG will result in owners and operators always taking up to 72 hours to return their sites to normal operations. It is reasonable to assume that if owners and operators were addressing these issues quickly before the NSPS, they will continue to do so after these amendments. Seventy-two hours is a limit, not a minimum. The EPA's regulations in no way interfere with the efforts of owners and operators to address problems as quickly as possible. In fact, the final regulations clarify that temporary flaring must stop when the issue giving rise to the need to flare has been resolved. The requirement only allows flaring for the duration of time necessary to return the site to normal operations. If that is accomplished in eight hours instead of 72, then the rule does not allow, let alone require, flaring for 72 hours.

The EPA finds that certain commenters overestimate the potential environmental consequences of revising the 24-hour requirement to a 72-hour requirement. If the regulations provide owners and operators with no options aside from shutting-in operations if repairs are incomplete after 24-hours, these circumstances may lead to depressurizing equipment directly to the atmosphere (*i.e.,* venting). A shut-in occurs when an owner or operator temporarily closes the valves on an oil or gas well to stop the flow of hydrocarbons, often for maintenance, safety, equipment issues, or economic issues. The act of restarting the well after a shut-in can result in significant emissions due to pressure buildup while the well was shut-in, as owners and operators perform blowdown operations to release pressure from the well, often resulting in significant releases of methane and other harmful emissions.

Venting in these situations may release far more harmful emissions than controlled flaring would over an additional 24 to 48 hours. Thus, a rigid 24-hour limit, when compared to what is being finalized, could result in marginally greater pollution, not less, undermining the EPA's emission reduction goals. Further, in accordance with 40 CFR 60.5377b(d), emissions from flares and ECD are to be controlled at 95 percent reduction efficiency (see also 40 CFR 60.5391c(b) within the model rule for the EG). While the change from 24 hours to 72 hours for flaring in these situations, and longer for exigent circumstances, can theoretically allow more flaring by total duration, the natural gas being routed to a flare during this time is still being controlled at a 95 percent reduction efficiency. And as noted above, any increase in emissions from flaring is speculative given the backstop requirement that flaring must cease as soon as the underlying issue is resolved.

Finally, while one commenter dismissed data from the Williston Basin as "outliers," this overlooks the fact that the data from the Williston Basin represent real operating conditions faced by numerous facilities.[90] The fact that the sample size from the Williston Basin is smaller does not mean that the issues operators face there are less legitimate. The EPA believes that utilizing a regulatory framework that fails to accommodate areas with severe climates and operational challenges would penalize responsible owners and operators working in these difficult environments. The information presented to the EPA clearly indicates that in some instances—and more than just a few outliers—owners and operators credibly require more than 24 hours to temporarily flare before they can resolve the problem and return the site to normal operations. It is not appropriate for the EPA to establish a rigid and universal, nation-wide, requirement that the Agency has credible reason to believe cannot be met. Allowing up to 72 hours for most situations, and providing a mechanism to go beyond 72 hours, will allow owners and operators the time they need while also ensuring that temporary flaring does not continue indefinitely or unchecked. To use an example from one commenter, flaring for 378 hours due to a separator backpressure valve issue where the site is accessible would not be in compliance with the finalized amendments. We believe that a fair and reasonable standard should reflect the full diversity of U.S. oil and natural gas operations. A flexible allowance permitting up to 72 hours of flaring under these circumstances is both more practical and environmentally responsible.

5. Consideration of Additional Limitations and Targeted Exceptions to Temporary Flaring

In response to the January 2025 Proposal to extend the allowable duration for flaring associated gas from 24 to 48 hours under certain situations, commenters also raised two distinct but related issues. The first is whether there should be a clear cutoff for flaring within the 48-hour period. Some commenters advocated for a more restrictive application of the proposed 48-hour allowance by recommending that the EPA adopt an additional cutoff

[90] Document ID No. EPA–HQ–OAR–2024–0358–0096.

mechanism. They requested that the EPA require owners and operators to stop flaring as soon as the repair, maintenance, or safety issue is resolved, even if that happens before the end of the 48-hour period. They argued that this was needed to avoid extra flaring that serves no technical purpose. For example, if a repair is done after 8 hours, the commenter asserts flaring should not continue for the full allowed temporary flaring duration. The commenter requested that the EPA clearly state that flaring must stop when the cause of the disruption is resolved.

Second, a separate set of comments urged the EPA to consider geographical targeted exemptions (*i.e.,* to explore whether exemptions to the flaring limit should apply only in certain geographic areas such as specific basins). These commenters argued that the EPA should not apply the proposed 48-hour flaring allowance across the country. Instead, they suggested that the Agency consider basin-specific exemptions where data shows they are needed. The commenters pointed to past EPA rules that have allowed for regional differences. For example, the EPA has given exemptions for Alaska North Slope facilities due to cold weather conditions. In this case, the commenter referred to the Temporary Flaring Survey data from the Williston Basin and said it does not support a nationwide change to the flaring limit. They further asserted that any extended flaring allowance based on that data should apply only in the Williston Basin.

These comments suggest that a blanket 48-hour allowance may not be the best fit for all situations. These comments and the EPA's responses are provided in sections IV.A.5.a and IV.A.5.b of this preamble.

a. Additional Cutoff To Limit Temporary Flaring

Comment: One commenter requested that, if the EPA finalizes the 48-hour allowance as proposed, the EPA explicitly include an additional cutoff for the stated allowed duration to ensure the temporary flaring or routing to control devices ceases as soon as the malfunction is resolved, including for reasons of safety, repair, or maintenance.[91] The commenter contended that it is necessary for the EPA to specifically put restrictions on the duration to require operators to stop temporary flaring when repairs or maintenance are completed, thus avoiding continued flaring longer than necessary during each incident. For example, the commenter stated that if a repair or maintenance is completed within eight hours of the need to temporarily flare associated gas, then the flaring of associated gas should be limited to eight hours, not a full 24 hours as allowed in the March 2024 Final Rule. The commenter recommended regulatory text changes to 40 CFR 60.5377b(d)(1) and (2) and 40 CFR 60.5391c(c)(1) and (2) placing a cutoff for temporary flaring to end as soon as the malfunction, safety concern, or maintenance repair is resolved, if it did not require the full 24 hours allowed in the March 2024 Final Rule.

Additionally, the commenter stated that their recommendations are consistent with other requirements in NSPS OOOOb and EG OOOOc, which place an upper limit on how long provisions for certain extenuating circumstances may apply before the baseline requirements once again take effect, including the allowance of temporary flaring until gas composition meets specifications or up to 72 hours, whichever is less (40 CFR 60.5377b(d)(4)); delayed repair of centrifugal compressors (40 CFR 60.5380b(a)(8)(i)), reciprocating compressors (40 CFR 60.5385b(a)(3)(i)), fugitive emissions components until the next scheduled shutdown or up to two years (40 CFR 60.5397b(h)(3)(i)), whichever is earliest; repairs of pressure relief devices at gas plants the next time monitoring personnel are onsite or within 30 days, whichever is sooner (40 CFR 60.5400b(d)(2)). The commenter supported this additional cutoff to ensure that temporary flaring is limited as much as possible.

Response: The EPA agrees with the commenter's recommendation that the finalized time for temporary flaring allowance of associated gas should operate as a maximum timeframe. Temporary flaring or routing of associated gas to control devices should end as soon as the malfunction, maintenance, or safety issue is resolved. The EPA's intent with the provisions for temporary flaring of associated gas is to allow necessary flexibility to manage equipment issues or emergencies, while limiting emissions to those which are associated with actions that are required to fix the problem. This approach will encourage owners and operators to limit flaring to the time necessary.

The EPA agrees that there is clear precedent for this type of backstop. The March 2024 Final Rule already includes a maximum time limit of 24 hours for temporary flaring to prevent avoidable emissions during operational disruptions.[92] Adding a requirement that flaring must cease when the issue is resolved builds on this principle.

The monthly and annual datasets provided by industry stakeholders show wide variation in flaring durations. The average flaring duration across all responses was 46 hours, but the median was four hours. This gap suggests that while some events last longer, most can be resolved much sooner. In particular, several months showed high percentages of events exceeding 24 and even 72 hours—up to 34 percent and 32 percent, respectively, in January. But in other months, most events were short, with medians below five hours. These numbers support the idea that many events can be resolved well before the maximum time is reached and that a cutoff based on when the issue is fixed would reduce emissions without affecting needed flexibility. Further, in the Temporary Flaring Survey, the Williston Basin data shows that the causes of temporary flaring vary, including equipment failures like compressor shutdowns, frozen gas lines, and power outages. We believe these events do not all require the same response time. Some events can be resolved in under 10 hours. Implementing requirements to end flaring once the cause is addressed will limit emissions to what is necessary for safe and reliable operations. Industry stakeholders have repeatedly stated that owners and operators are already taking steps to reduce flaring times and that a 72-hour allowance would promote planning and operational changes to further reduce emissions.[93] The EPA concludes that a backstop limit and a requirement to stop flaring when the issue is resolved can work together to maintain the Agency's objectives while allowing industry to respond to operational needs in an efficient and timely manner.

b. Alternative Exemptions (*e.g.,* Basin-Specific)

Comment: One commenter suggested that the EPA consider adopting basin-specific exemptions from the temporary flaring provisions rather than extending the temporary flaring allowance beyond 24 hours for all wells nationwide.[94] The commenter acknowledged, however, that the current record does not support basin-specific exemptions. In particular,

[91] Document ID No. EPA–HQ–OAR–2024–0358–0096.

[92] (Docket ID: EPA–HQ–OAR–2021–0317) Preamble, Table 17—Situations and Durations Where Associated Gas May Temporarily be Routed to a Flare or Control Device.

[93] Document ID No. EPA–HQ–OAR–2024–0358–0044.

[94] Document ID No. EPA–HQ–OAR–2024–0358–0096.

the commenter recommended that the EPA consider which limited exceptions to the 24-hour duration allowance are warranted and specify an appropriate allowance for temporary flaring or routing to control based on data that supports that exception. According to the commenter, the EPA has historically provided location-specific exceptions in its oil and gas standards that account for the unique circumstances those owners and operators face. The commenter referred to a statement the EPA made: ''the information provided by petitioners is persuasive in demonstrating that a blanket 24-hour limit on temporary flaring can pose compliance challenges for certain owners and operators.'' [95]

The commenter summarized key observations from the 166 instances that the Temporary Flaring Survey API provided for temporary flaring of associated gas in the Williston Basin (see page nine of commenter's letter) and concluded that the Williston Basin data provides insufficient evidence to provide a blanket nationwide exemption. The commenter further expressed that though their position is that the data are insufficiently clear to warrant adjusting the March 2024 Final Rule at this time, any change in the duration of the temporary flaring allowance based on the Williston Basin data should be limited to that basin. The commenter noted that the EPA took similar actions on limited exceptions for fugitive emissions monitoring requirements and process controllers on the Alaska North Slope, citing concerns about the technical feasibility of conducting monitoring when temperatures are below the operating envelope of the monitoring technologies, and the EPA noted ''there is no assurance that the initial and semiannual monitoring that must occur during that period of time are technically feasible.'' [96]

Regarding process controllers, the commenter highlighted that the EPA provided two standards for sites in Alaska in the March 2024 Final Rule: zero emissions for all process controllers at sites with access to electrical power, and the use of process controllers with low emission rates at sites with no access to electrical power (40 CFR 60.5390b(b)). Instead of the blanket move to allow 48 hours for temporary flaring as proposed nationwide, the commenter reiterated that any changes to the duration allowance for temporary flaring based on the Williston Basin data should be limited to the Williston Basin and based on a demonstrated need in the basin.

Response: Regarding the comment requesting that the EPA consider adopting basin-specific exemptions from the temporary flaring provisions rather than extending the temporary flaring allowance beyond 24 hours for all wells nationwide, the EPA acknowledges that we have historically allowed some location-specific variations in oil and gas standards to reflect operational challenges that are unique to certain geographic regions. However, we do not find that such an approach is necessary or supported by the current data for this rule. In the March 2024 Final Rule, the Alaska-specific provisions cited by the commenter were granted because of distinct technical challenges related to that region (*i.e.,* controllers without electric power and uniqueness of large compressors different from those in the lower 48 States [97]). For example, we took a different approach for process controllers in Alaska at sites without reliable access to power.[98] This was in part due to Alaska's northern latitude, where long periods of darkness during winter reduce the ability of solar panels to generate electricity. That situation presented a clear, location-specific operational barrier that justified a different standard for certain sources. The examples presented by the commenter both involve subcategorization that resulted in different standards for different sources. The differences there were meaningful enough to justify different treatment. However, here, the differences are not as pronounced or meaningful, and the different treatment that commenters advocate for is only in regard to a limited variation provision that comprises one piece of the larger applicable standard (these amendments are not changing the substance of the NSPS standards or the EG presumptive standards for associated gas).

The circumstances described by the commenter and the data for the Williston Basin and other regions do not meet the same threshold as the examples that commenters cite and do not warrant the same outcome of creating subcategories. The Temporary Flaring Survey shows that 17 percent of temporary flaring events across all reported basins lasted longer than 24 hours, and 15 percent exceeded 72 hours. While these numbers suggest some operational challenges, the data also show significant variation across both the durations and underlying causes of these flaring events. For instance, the monthly flaring dataset shows that in many months, the median flaring duration was just four to six hours, even though averages were higher due to outlier events. In June and July, for example, the average flaring durations were 11 and 19 hours, respectively, with medians of four hours. This pattern suggests that while extended events do occur, many are resolved within a short timeframe, even in colder months. In the Williston Basin dataset of the Temporary Flaring Survey, temporary flaring causes range from compressor shutdowns and frozen gas lines to facility restarts and power outages. These are operational issues that may occur across multiple basins. The possibility of inclement weather as a contributing factor to site inaccessibility is not unique to any one location. The Temporary Flaring Survey shows that events flagged as ''[u]nknown'' accounted for a much higher average flaring duration (86 hours) compared to events where the impact of weather was known to be present (21 hours) or absent (36 hours). This inconsistency indicates that factors beyond location such as the nature of the malfunction, site accessibility, and access to equipment play a large role in extended flaring durations.

Accordingly, we find that a single, flexible nationwide approach with clear, uniform provisions for additional time is more appropriate, equitable, and easier to implement than finalizing different maximum flaring times for different geographic regions of the country. As some commenters suggested, basin-specific timelines would likely introduce unnecessary complexity into an already complex regulatory scheme, which could result in enforcement and compliance inconsistencies. The standards for associated gas are already subcategorized in the NSPS based on when a new well commenced construction. (*See* Table 16 in the March 2024 Final Rule).[99] These amendments only address two of the four scenarios for temporary flaring (*see id.* at Table 17). Further, the presumptive standards in the EG model rule are also already subcategorized on different terms than the NSPS (*see id.* at Table 4). These temporary flaring provisions are only one piece of the regulatory scheme for associated gas, and they do not relate to

[95] 90 FR 3740 (January 5, 2025).

[96] 83 FR 10628, 10632 (March 12, 2018).

[97] The ''lower 48'' consists of the 48 adjoining U.S. States and the District of Columbia of the U.S. The term excludes the only two noncontiguous States, which are Alaska and Hawaii, and all other offshore insular areas, such as the U.S. territories of American Samoa, Guam, the Northern Mariana Islands, Puerto Rico, and the U.S. Virgin Islands.

[98] Docket ID No. EPA–HQ–OAR–2021–0317.

[99] 89 FR 16887 (March 8, 2024).

the standards directly. Layering basin-specific variations on top of this scheme for certain instances of temporary flaring, which generally should not occur often, is too complex for little to no benefit when considered in conjunction with the requirement that flaring must cease when the issue giving rise to the need to temporary flare is resolved.

Lastly, the record does not support the conclusion that any one basin faces persistent technical barriers that would justify a regional variation to the originally proposed 48-hour or finalized 72-hour temporary flaring limit. Instead, we support an approach that allows limited extensions under exigent circumstances, as discussed in section IV.A.1 of this preamble, but maintains a consistent framework across all basins. This ensures fairness, limits emissions, and encourages continued operational innovation in the oil and gas industry.

B. Vent Gas NHV Continuous Monitoring Requirements and Alternative Performance Test (Sampling Demonstration) Option for Flares and Enclosed Combustion Devices

The March 2024 Final Rule requires owners and operators to perform NHV sampling for flares and ECD through continuous monitoring of NHV or through periodic testing with sampling demonstrations. As stated in the January 2025 Proposal, industry petitioners stated in their reconsideration petitions that the compliance demonstrations are unnecessary, technically infeasible, and provide a limited timeline for compliance. The petitioners argued that over 99 percent of historical Btu stream data already complies with the prescribed minimum NHV content values (depending on flare type) outlined in the March 2024 Final Rule. Industry petitioners asserted that NHV content is usually a concern when inert gases are added to the process streams, which typically occurs during scheduled situations and is known to the operator of the affected source.

Based on information from these petitions, as well as further information provided by industry, in the January 2025 Proposal the EPA proposed changes to the continuous monitoring requirements and alternative performance test options (sampling demonstration) of NHV for flares and ECD. First, for the continuous monitoring requirement, we proposed to expand the streams that are exempt from monitoring NHV to include unassisted flares and ECD at new sources, and unassisted, air-assisted, and steam-assisted flares and ECD at existing sources. We also proposed to replace the general exemption from NHV monitoring for associated gas for any control device used at ''well site affected facilities'' with NHV monitoring that is more reflective of industry operations. Additionally, we proposed to require NHV monitoring for streams where inert gases were added and for operational scenarios where NHV is known to decrease (*e.g.,* nitrogen and acid gas removal, glycol dehydration, etc.) in flares and ECD that are subject to the 200 or 300 Btu/scf minimum requirements. The EPA relied on data provided by industry, which showed reduced NHV from the dilution of inlet streams by effluent streams with known high content of inerts, such as those from amine units or produced water tank streams. In the event of stream dilution (for any reason), owners and operators would need to satisfy more robust recordkeeping and reporting requirements. Second, for the alternative performance test (sampling demonstration) requirements, we proposed to allow breaks during weekends and holidays for the March 2024 Final Rule's consecutive 14-day sampling demonstration requirements to account for reasonable operational pauses. We also addressed ambiguity regarding the location of NHV grab sampling methods by specifying in the January 2025 Proposal that samples should be taken upstream of the control device, provided that the sample is representative of the gas being introduced to the control device. Finally, in the January 2025 Proposal the EPA clarified NHV testing must be reported in volumetric units (Btu/scf) instead of specific units (Btu/lb) in order to facilitate consistency in reporting.

The EPA received several comments on the proposed amendments regarding the NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and ECD in the January 2025 Proposal. Highlights of these comments and the EPA's responses are provided, as well as discussion of changes from the January 2025 Proposal as applicable. This preamble does not discuss the EPA's response to any of those comments. The agency's responses are available in the EPA's RTC document (Chapter 4) for the final rule.[100]

[100] Reconsideration of Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review: Response to Public Comments on the January 2025 Proposed Rule (90 FR 3734; January 15, 2025). See Docket No. EPA–HQ–OAR–2024–0358.

1. 60-Day Deadline

In the January 2025 Proposal, the EPA proposed to allow 60 days for owners and operators to conduct the continuous NHV monitoring required by one of the options in 40 CFR 60.5417b(d)(8)(ii)(A) through (D), if the results of the periodic sampling (*i.e.,* three samples every five years) indicate that the NHV is less than 1.2 times the applicable threshold NHV level in the rule. The EPA considers it necessary to specify a timeframe to install and operate the required continuous monitors to provide owners and operators with regulatory certainty for when this must occur. We consider 60 days to be an expedited time schedule for the installation of continuous monitoring systems, but we also consider it a reasonable timeframe for installing the necessary grab sampling systems to automatically collect samples at least once every eight hours as provided in 40 CFR 60.5417b(d)(8)(ii)(D). The proposal would require facilities to collect grab samples every eight hours until such time that a continuous monitor can be installed, and installation of such a system may require more than 60 days. We requested comment on the proposed 60-day compliance provision when a five-year sampling event indicates the vent stream is not sufficiently above the required NHV.

Comment: One commenter supported the EPA's proposed 60-day deadline to require continuous NHV monitoring after either a periodic sample or a post-process change re-evaluation demonstrates the flare or ECD inlet gas is below the applicable NHV limit.[101] The commenter stated that more deadlines are necessary to provide clear compliance obligations. The commenter also suggested that where a post-NHV demonstration periodic sample is below the applicable NHV limit, the operator must commence continuous NHV monitoring or recomplete the NHV demonstration within 60 days of receiving the analytical results. The commenter suggested that the opportunity to recomplete the NHV demonstration would account for the possibility of errors in sampling or analysis.

Response: The EPA received only supportive comments regarding the proposed clarification of allowing 60 days for implementing the continuous NHV monitoring required by one of the options in 40 CFR 60.5417b(d)(8)(ii)(A) through (D) if the results of the periodic sampling (*i.e.,* three samples every five years) indicate that the NHV is less than

[101] Document ID No. EPA–HQ–OAR–2024–0358–0088.

1.2 times the applicable threshold NHV level in the rule. Hence, we are finalizing this particular provision as proposed. Owners and operators could resolve any potential error in sampling or analysis by implementing a continuous NHV monitor within the newly clarified 60-day window.

Moreover, 40 CFR 60.5417b(d)(8)(iii)(E) and 40 CFR 60.5417c(d)(8)(iii)(E) requires that if process operations are revised that could impact (*i.e.,* lower) the NHV of the gas sent to the enclosed combustion device or flare, such as the removal or addition of process equipment, owners and operators must perform a re-evaluation of the NHV of the gas stream. The EPA is clarifying that this re-evaluation must be performed within 60 days of the process operations being revised, on those enclosed combustion devices and flares subject to NHV testing.

2. Revisions to Inlet Gas Streams Exempt From Monitoring

Based on information provided by petitioners after the publication of the March 2024 Final Rule regarding NHV characteristics of sample streams, in the January 2025 Proposal the EPA proposed changes to the March 2024 Final Rule that would expand the scope of the exclusion for the NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option so that the following control devices would not be required to make any such demonstration: unassisted flares or ECDs at new sources; and unassisted, air-assisted, or steam-assisted flares or ECDs at existing sources. New data submitted in API and AXPC's joint petition for reconsideration dated April 2024 demonstrated that, for over 22,000 NHV low-pressure (LP) data points, 99.5 percent of those data points showed that the NHV was at least 800 Btu/scf and more than 99.9 percent of those data points showed that the NHV was at least 300 Btu/scf. Notably, these data were consistent across different basins.[102] Data supplied by GPA Midstream in its July 2024 letter supported its prior petition submittals that gas streams in the midstream consist of natural gas and field gas with NHVs greater than 1,000 Btu/scf, with the exception of certain streams in which inert gases or other known low-NHV streams were added.[103] Because these new data further demonstrate that the NHV of the vent gas is consistently well above the 200 or 300 Btu/scf vent gas requirements for these control devices when inerts are not present, and because there are no combustion zone or dilution parameters for these control devices, the EPA proposed to determine that an expanded exclusion from the monitoring requirements is appropriate.

In the January 2025 Proposal, the EPA did not propose to exclude pressure-, steam-, or air-assisted flares or ECD from the NHV compliance demonstration requirements for new sources. After the January 2025 Proposal, based upon the EPA's solicitation for comment for the sampling requirements for pressure-assisted flares and ECDs at new and existing sources and for air- and steam-assisted flares or ECDs at new sources,[104] in April 2025 API supplemented its comment letter with new high-pressure (HP) stream data (39,000 samples) from 11 basins with over 99.5 percent of these data greater than 800 Btu/scf, which was comparable to that of the LP NHVs previously analyzed in 2024. Again, these were consistent across different basins.[105] For the combined data sets from April 2024 and April 2025, which consisted of over 60,000 data points from both LP and HP gas streams, over 99.5 percent of the data showed NHV contents of at least 800 Btu/scf and over 99.9 percent of the data showed NHV contents of at least 300 Btu/scf.[106] In this combined data set, over 99 percent of the data samples from LP gas streams resulted in a NHV content of greater than 900 Btu/scf and over 95 percent of the data samples from HP gas streams resulted in a NHV content of greater than 900 Btu/scf. Of particular note, while less than 0.5 percent of the total samples yielded NHV contents of 800 Btu/scf or less, these instances were from known scenarios where inerts were added, namely vent gas streams from nitrogen removal units (NRU), acid gas removal (AGR) system amine regenerator still columns, glycol dehydrator unit reboilers without water removal, compressors in acid gas service, or vent streams containing water or CO_2 used for EOR.

As demonstrated by the July 2024 GPA Midstream data set, the addition of inert gases or streams from amine units or produced water tanks can decrease the NHV content of the gas stream to the point that the NHV thresholds for non-pressure-assisted flares or ECD may not be achieved. In addition to sources of inert streams previously identified in the March 2024 Final Rule (*i.e.,* streams from compressors in acid gas service and streams from EOR facilities), the July 2024 GPA Midstream letter explained that other operating scenarios can result in the addition of low-Btu streams into the vent gas stream, which lowers the overall NHV for the vent stream.

Based upon the information and data provided after the publication of both the March 2024 Final Rule and January 2025 Proposal, which demonstrated that over 99.5 percent of the data (consisting of both LP and HP sources) showed NHV contents of 800 Btu/scf or greater and over 99.9 percent of the data showed NHV contents of 300 Btu/scf or greater, the EPA is expanding the streams that are exempt from monitoring due to high NHV content to include all flare and ECD for both new and existing sources.

We are finalizing that NHV sampling is only required for any new or existing flare or ECD in cases where there are contributions from inerts, and for other miscellaneous scenarios which decrease the NHV content, using the continuous monitoring requirements and alternative performance test (sampling demonstration) options currently prescribed in the NSPS OOOOb and EG OOOOc rules and summarized in section III.B of this preamble.[107] The EPA expects that the operational scenarios described in section IV.B.2.c. of this preamble can be easily validated and documented through the physical presence (or absence) of process equipment, process piping, engineering analysis, or process flow diagrams in order to determine when the owner or operator should monitor the NHV of the stream.

For example, in the case of the acid gas removal (AGR) system amine regenerator still column vent gas, it would be easy to trace process piping to determine whether the vent stream was routed to a dedicated control device or was combined with affected facility vent gas streams. Similarly, for the glycol dehydration unit reboiler vent gas, the lack of a process condenser would indicate that higher water content (and lower Btu) reboiler vent gas streams were combined with affected facility vent gas streams. The use of nitrogen as

[102] 99 percent of the data were from five basins: Permian, Anadarko, Gulf Coast (Eagleford), Williston (Bakken), and Powder River. See March 18, 2024, API/AXPC Slides in Docket ID No. EPA–HQ–OAR–2024–0358.

[103] Document ID No. EPA–HQ–OAR–2024–0358–0094.

[104] 90 FR 3748 (January 15, 2025).

[105] 97 percent of the data were from eight basins: Permian, Anadarko, Gulf Coast (Eagleford), Williston (Bakken), Powder River, East Texas, Appalachian, and Arkla (Haynsville). See April 2, 2025, API Slides in Docket ID No. EPA–HQ–OAR–2024–0358.

[107] See 40 CFR 60.5417b(d)(8) and 40 CFR 60.5417c(d)(8).

a blanket gas can be readily determined through the presence of nitrogen storage, supply systems, and process piping. Finally, we expect that storage tanks with water content high enough to depress overall NHVs typically would not meet the applicability thresholds of the rule and would not be combined with other vent streams routed to a flare or ECD. However, when gas streams from produced water tanks are vented to controls, vent lines from these tanks can be traced to identify sources that require monitoring or sampling.

Since we proposed to remove the general monitoring exemption for when the only inlet gas stream to the flare or ECD is associated gas from a well affected facility, we also directly resolved one of the issues raised in the May 2024 EIP et al. petition. We consider the data submitted by the industry petitioners to support the proposed exclusion from monitoring for flares and ECD subject to a vent gas NHV requirement of 200 or 300 Btu/scf (and not subject to NHV_{cz} and NHV_{dil} requirement) when no inerts are present because the results were consistently much higher than these levels. The May 2024 EIP et al. petition also contended that the EPA did not support its conclusion in the March 2024 Final Rule that initial assessments of flares and other control devices, in lieu of continuous monitoring, can capture the variability of NHV in the oil and gas sector. The EPA has concluded that the data submitted by the industry petitioners supports the conclusion that the NHV demonstrations required for pressure-, air-, and steam-assisted control devices are adequate to show that the NHV from those demonstrations is above the required thresholds specified by the rule and that continuous monitoring is not needed. When inerts are added intermittently or process operations change in ways that that may lower the NHV, the proposed standards require a re-demonstration with a new 14-day sampling effort.[108] The re-demonstration would consider the variability associated with these operations and determine a reasonable lower-range value to use in compliance assessments. As such, we proposed that the sampling requirements, with the revisions proposed and now being finalized, are robust and sufficient to demonstrate that continuous monitoring is not needed when the NHV of the gas stream being controlled is sufficiently high, when considering the range of vent gas and assist gas flow rates, to meet the required standards.

While we previously excluded monitoring for associated gas from the NHV compliance demonstration requirements, some petitioners have identified instances where the NHV for associated gas streams could be compromised. Specifically, the use of water or CO_2 flooding for EOR could introduce significant inerts as part of the associated gas produced and thereby lower the NHV of the associated gas. We found the information presented by the petitioners compelling and therefore proposed to conclude that the March 2024 Final Rule's exclusion of associated gas from the NHV compliance demonstration requirements is overly broad. Because the definition of associated gas in the March 2024 Final Rule specifically excludes these inert gases that may be released with the natural gas during the initial stage of separation after the wellhead, there are cases where associated gas can have high levels of inerts and low NHV. Therefore, the EPA proposed to remove this exclusion for associated gas in its entirety and also requested comment on the proposed removal of the associated gas monitoring exemption, as well as any additional miscellaneous operating scenarios that can compromise the NHV for associated gas streams as well as all flare types and ECD.

a. Exemptions From NHV Monitoring

Comment: Several commenters requested exemptions from all NHV monitoring. One commenter stated that the EPA's proposal to reconsider the streams that are exempt from monitoring due to high NHV content for flares or ECD at new and existing sources would allow for additional flexibility and compliance options for regulated entities.[109] The same commenter asserted that extending the exemption from NHV sampling/monitoring requirements for affected facilities under NSPS OOOOb and EG OOOOc to streams other than associated gas to include other equipment with consistently high NHV vent streams would allow for many upstream facilities to demonstrate effective control of VOCs and methane while providing flexibility and reducing the compliance burden associated with continuous monitoring. The commenter suggested that the EPA consider expanding the streams exempt from monitoring for unassisted flares or ECD at new sources, and unassisted, air-assisted, and steam-assisted flares or ECD at existing sources to create consistency between requirements for new sources and existing sources. The commenter added that this would provide flexibility and lessen the compliance burden associated with applying the monitoring standards to affected facilities under NSPS OOOOb and EG OOOOc.

Another commenter urged the EPA to remove all NHV monitoring requirements for all upstream sector flares and ECD in both the NSPS OOOOb and EG OOOOc, regardless of whether inert gas is added, and to remove the NHV standards which prompt such monitoring.[110] The commenter stated that operators in the Williston Basin already collect and analyze data throughout the well's lifecycle for permitting, compliance, and reporting purposes and that midstream companies sample associated gas routinely (often monthly, including composition and NHV) to handle custody transfer payments. The commenter stated that these operators sample and analyze using established standards and that therefore the March 2024 Final Rule NHV monitoring requirements are redundant.

The same commenter added that the manufacturer of control devices specifies the minimum or required range of the NHV for the inlet gas which is necessary to operate the control device effectively. Regarding lower-Btu gas, the commenter stated that flare and ECD technology exists (and continues to evolve) which can ensure stable combustion at lower heating values and that imposing rigid NHV monitoring requirements can limit innovation. The commenter stated that upstream sector flares and ECD have consistently been designed and tested to ensure high combustion efficiency (destruction removal efficiency (DRE) exceeding 99 percent) without the need for complex NHV monitoring typically required for petroleum refinery flares. The commenter pointed to comments in the May 2024 API and AXPC petition which highlighted fundamental differences between upstream sector flares and petroleum refinery flares regarding NHV requirements. The commenter explained that upstream flares are not designed with NHV requirements because they operate under non-steady state conditions, with a more consistent gas composition, including NHV. In contrast, the commenter noted that the Refinery MACT includes NHV requirements and operates under steady state conditions with varying gas

[108] 800 Btu/scf for pressure-assisted flares and 270 Btu/scf for steam- and air-assisted flares.

[109] Document ID No. EPA–HQ–OAR–2024–0358–0085.

[110] Document ID No. EPA–HQ–OAR–2024–0358–0091.

composition (which can include different NHV contents). The commenter stated that upstream flares are specifically designed to maintain high combustion efficiency even in non-steady state conditions due to the limited variability of the vent gas composition and relatively few gas streams routed to the control device.

Several commenters requested that NHV continuous monitoring only apply in situations where inert gases are introduced into the vent gas stream.[111] Two of the commenters [112] referred to data [113] previously provided to the EPA which they state demonstrates that oil and gas facilities consistently exceed the minimum NHV limits, except for known scenarios.

One commenter requested that the EPA not require NHV monitoring unless inert gases are added or for other miscellaneous scenarios which decrease vent gas NHV regardless of type of control device.[114] The commenter stated that, in previous comments submitted to the EPA, they provided data that shows the vent gas NHV is typically well above 900 Btu/scf, and therefore the NHV monitoring requirements are unnecessary except in specific operations which introduce inert gases into the vent gas stream. The commenter provided that the previous data set represented LP vent gas streams and included over 22,000 data points from 18 operators covering approximately 4,200 sites, including well sites, central production facilities, and compressor stations. A second data set for HP vent gas streams, collected in the same operator survey in coordination with AXPC, is included in the commenter's letter and represents an additional 39,000 data points from 12 operators covering approximately 22,100 sites, primarily from well sites and central production facilities. The commenter concluded that NHV monitoring should only be required when inert gases are added or for other miscellaneous scenarios which decrease vent gas NHV regardless of type of control device.

Another commenter also urged the EPA to exempt NHV monitoring for flares and ECD that control associated gas from any oil well (not just well affected facilities under NSPS OOOOb or well designated facilities under EG OOOOc).[115] The commenter explained that the composition of associated gas does not change due to regulatory applicability, and the current associated gas exemption arbitrarily limits the scope of the exemption.

Lastly, a commenter recommended that the EPA allow the NHV monitoring exemption to apply to pressure-assisted control devices.[116] The commenter referenced the January 2025 Proposal in which the EPA states that because the NHV of methane (896 Btu/scf) is not significantly higher than the required minimum NHV of 800 Btu/scf for pressure-assisted flares and ECD, the Agency will continue to require either continuous monitoring or alternative performance testing (14-day NHV test) for these devices. The commenter urged the EPA to reconsider this approach, which they say is not supported by the record and is contrary to common sense. The commenter further provided that the EPA further stated in the January 2025 Proposal that ''. . . we find that it is much easier for the NHV in the vent gas samples from these control devices to decrease and approach the 800 Btu/scf NHV threshold. . .'' According to the commenter, this reason does not support costly continuous monitoring.

Conversely, two commenters opposed the EPA's proposal to exempt flares and ECD from NHV monitoring. One of the commenters agreed with the EPA's proposal to require certain flares and other control devices controlling emissions from associated gas to monitor or sample for NHV. According to the commenter, the EPA must do so given that some petitioners have identified instances where the NHV for associated gas streams could be compromised, such as in water or CO_2 flooding which can introduce a large amount of inerts as part of the associated gas produced. However, the commenter disagreed with the EPA's proposal to require this monitoring or sampling only for pressure-assisted flares and other controls at new and existing sources and air- and steam-assisted flares and other controls at new sources. The commenter stated that the EPA must also require NHV monitoring or sampling for unassisted flares at new and existing sources and air- and steam-assisted flares at existing sources. The commenter stated that the EPA has failed to establish that the NHV of gases sent to flares and other controls, including those where no inert gases are added and nothing else decreases the NHV content of the inlet stream gas, will always be above the March 2024 Final Rule's NHV limits. According to the commenter, this means that the EPA cannot rationally justify a complete exemption from NHV monitoring and sampling.

The other commenter strongly opposed the EPA's proposal to remove NHV monitoring requirements for all new unassisted flares and ECD (with limited exceptions due to inerts) and for existing air-assisted and steam-assisted flares and ECD and asserted that the EPA has changed its position without adequate justification.[117] The commenter urged the EPA to maintain NHV monitoring requirements for all unassisted flares and ECD.

The same commenter referenced the EPA's justification for its proposed exemption from all NHV monitoring for unassisted flares and ECD, which cited new data [118] provided by API, AXPC, and GPA Midstream that the EPA claims ''appear to demonstrate that the NHV of the vent gas is consistently well above the 200 or 300 Btu/scf vent gas requirements for these control devices when inerts are not present, and because there are no combustion zone or dilution parameters for these control devices.'' [119] The commenter suggested that several deficiencies in the data cut strongly against the EPA's decision to exempt all unassisted flares and ECD from the monitoring requirements. The commenter disagreed that the Temporary Flaring Survey contains enough information to ensure the NHV figures represent the entire vent gas stream going to the flare or ECD. The commenter contended that because the data sets do not specify that all samples were taken after all vent streams were combined, it is inappropriate for the EPA to make a sweeping exemption based solely on the data presented.

The same commenter also supported the proposed removal of the exemption for associated gas waste streams, which they state is supported by the record. The commenter agreed with the EPA's assessment of information, provided that the NHV of associated gas does not always exceed the minimum limits as

[111] Document ID No. EPA–HQ–OAR–2024–0358–0083, –0088, –0090, –0092, –0093, –0094, –0095.

[112] Document ID No. EPA–HQ–OAR–2024–0358–0092, –0095.

[113] See, *e.g.,* Letter from American Petroleum Institute and American Exploration & Production Council, to Michael S. Regan, US EPA Administrator, Provisions Creating Immediate Compliance and Implementation Issues EPA's Final Rule ''Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,'' 5, EPA–HQ–OAR–2024–0358–0009 (April 5, 2024).

[114] Document ID No. EPA–HQ–OAR–2024–0358–0083.

[115] Document ID No. EPA–HQ–OAR–2024–0358–0088.

[116] Document ID No. EPA–HQ–OAR–2024–0358–0094.

[117] Document ID No. EPA–HQ–OAR–2024–0358–0096.

[118] See API–AXPC NHV Survey Results v1.0 at *https://www.regulations.gov/document/EPA-HQ-OAR-2024-0358-0044;* July 31, 2024 Email from GPA (Response for additional information) at *https://www.regulations.gov/document/EPA-HQ-OAR-2024-0358-0039.*

[119] See 90 FR 3747 (January 15, 2025).

the EPA expected it would when it finalized the exemption in the March 2024 Final Rule. Further, the commenter agreed that the information provided demonstrates that associated gas can be combined with inerts, which in turn may reduce the NHV below the required minimum thresholds. The commenter urged the EPA to expand the inclusion of NHV monitoring for unassisted flares and ECD where the only vent stream is associated gas for these reasons and for the reasons discussed in other remarks by the commenter which address the EPA's proposed exemption of unassisted flares and ECD from all NHV monitoring.

Response: The EPA received numerous comments regarding the vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and ECD discussed in the January 2025 Proposal.

In general, most commenters were in favor of the EPA's proposal to expand the streams to include unassisted flares or ECD at new sources and to include unassisted, air-assisted, and steam-assisted flares or ECD at existing sources, and to only require NHV monitoring for streams where inert gases were added or in the event of operational scenarios where NHV is known to decrease. However, most commenters disagreed with the EPA's proposal to continue to require the NHV monitoring that is currently required for all pressure-, air-, and steam-assisted flares or ECD at new sources and for pressure-assisted flares or ECD at existing sources.

To support this argument, as discussed in section IV.B.2 of this preamble, in April 2025 API provided new HP stream data (39,000 samples) from 11 basins with over 99.5 percent of these data greater than 800 Btu/scf, which was comparable to that of the LP NHV previously analyzed in 2024. For the combined data sets from April 2024 and April 2025, which consisted of over 60,000 total combined data points from both LP and HP gas streams, over 99.5 percent of the data showed NHV contents of at least 800 Btu/scf and over 99.9 percent of the data showed NHV contents of at least 300 Btu/scf. In this combined data set, over 99 percent of the data samples from LP gas streams resulted in an NHV content of greater than 900 Btu/scf and over 95 percent of the data samples from HP gas streams resulted in an NHV content of greater than 900 Btu/scf. The EPA reviewed the ''Sample Description/Source'' field in both the LP and HP data sets and concluded that the sources for which NHVs were determined are representative of gases that may be controlled by a flare or ECD. In turn, the EPA found this additional data form a robust, reliable, and representative data set to support a compelling argument to include both the LP and HP data (which comprises data from unassisted, air-assisted, and steam-assisted flares and ECD) as its justification to expand the streams that are exempt from monitoring (due to typically high NHV contents, on average) to include all flare and ECD for both new and existing sources.[120]

While the EPA recognizes that in some instances sources may not achieve the applicable and prescribed NHV content values in NSPS OOOOb and EG OOOOc, industry commenters have presented sufficient information to conclude that these instances occur where inert gases are added or under other miscellaneous scenarios that decrease the NHV content of the inlet stream gas to all flare and ECD for both new and existing sources. As such, and as proposed, the EPA is requiring an NHV demonstration where inert gases are added, or for other miscellaneous scenarios that decrease the NHV content of the inlet stream gas for all flare and ECD for both new and existing sources. The EPA is also finalizing recordkeeping and reporting requirements to indicate whether the flare or ECD receives (or does not receive) inert gases or other streams that may lower the NHV of the combined stream, and, if so, a description of the operating scenario(s) that may lower the NHV of the combined stream through the introduction of those inert gases or other streams. Moreover, the EPA is also clarifying that when a required NHV demonstration is performed, the samples must be taken during the period with the lowest expected NHV (*i.e.,* the period with the highest percentage of inerts).

Regarding the comments opposing the January 2025 Proposal in this respect, one commenter [121] asserted that the EPA changed its position without adequate justification and lacked sufficient evidence to support such an exemption. The EPA disagrees. The combined data set described earlier in this response presented tens of thousands of data points (*i.e.,* fuel analysis samples for NHV content) for consideration and analysis. Moreover, as the EPA has already discussed in this preamble, it will not completely exempt flares and ECD as a whole from all NHV monitoring. That is, the EPA will still require an NHV demonstration where inert gases are added, and for other miscellaneous scenarios that decrease the NHV content of the inlet stream gas for all flare and ECDs for both new and existing sources. Given the EPA received over 60,000 data points for consideration and analysis, which were spread over the primary basins that geographically represent the oil and gas industry, with over 99.5 percent of the results being above the NHV thresholds currently prescribed by the NSPS OOOOb and EG OOOOc rules, the EPA considers the data submitted to be sufficiently reliable and persuasive to finalize the NHV exemptions included in this action. Moreover, by providing these NHV exemptions, the EPA believes that the industry will be in a better position to redirect and focus its cost expenditures, manpower, and emissions reduction efforts on the issues of most concern, such as equipment inspections, maintenance, and leak prevention measures.

Finally, the EPA is finalizing its proposal to replace the general exemption from NHV monitoring for associated gas for any control device used at ''well site affected facilities'' with NHV monitoring that is more reflective of industry operations. However, consistent with the finalized rule requirements for all flare and ECDs, associated gas streams will still be subject to NHV monitoring where inert gases are added, or in the event of operational scenarios where NHV is known to decrease.

b. Distinction of ''New'' and ''Existing'' Flares and Enclosed Combustion Devices

Comment: One commenter expressed disagreement with the EPA's distinction between ''new'' and ''existing'' flares and ECD, especially as it relates to proposed exemptions from NHV monitoring because, in practice, this effectively exempts all flares and ECD from NHV monitoring unless the flare or ECD is brand new.[122] According to the commenter, that means that only new affected facilities using new flares and ECD would be required to comply with the NHV monitoring requirements, and any modified or reconstructed affected facilities (and existing designated facilities) would be exempt from these provisions. The commenter believed that the EPA has not explained or

[120] As summarized in footnotes 106 and 108, 99 percent of the LP data were from five basins and 97 percent of the HP data were from eight basins, which geographically represent the primary basins located throughout the United States.

[121] Document ID No. EPA–HQ–OAR–2024–0358–0096.

[122] Document ID No. EPA–HQ–OAR–2024–0358–0096.

justified this type of distinction related to flares and ECD nor how these exemptions for ''existing'' flares address the concerns about ''pervasive issues with combustion sources.'' [123]

The commenter further asserted that control devices, including flares and ECD, are not by themselves ''new'' or ''existing'' sources under the NSPS or EG. Instead, these control devices are used to meet certain emission reduction standards for ''new'' affected facilities or ''existing'' designated facilities. Therefore, the commenter contended that the EPA must clearly define how it distinguishes the terms ''new'' and ''existing'' for purposes of the exemptions proposed if it moves forward with finalizing any exemptions from NHV monitoring.

Response: For the purposes of this final rule, ''new'' sources are designated as NSPS OOOOb sources, which are crude oil and natural gas facilities for which construction, modification, or reconstruction commenced after December 6, 2022, and ''existing'' sources are designated as EG OOOOc sources, which are crude oil and natural gas facilities for which construction, modification, or reconstruction commenced on or before December 6, 2022.

Based on the revisions to both NSPS OOOOb (*i.e.,* new, modified, and reconstructed sources) and EG OOOOc (*i.e.,* existing sources) as a result of this final rule, NSPS OOOOb sources and EG OOOOc sources will now have identical NHV sampling requirements and exemption qualifiers, with the exception of the NHV_{cz} and NHV_{dil} requirements that will only apply to NSPS OOOOb sources, as described in section IV.B.5 of this preamble. Hence, any distinction between ''new'' and ''existing'' sources would no longer apply in this context as it relates to the exemptions from NHV monitoring, since both ''new'' and ''existing'' sources will now have the same NHV sampling requirements and categorical exemptions with the finalization of this rulemaking.

c. Inert Gas and Other Vent Gas Stream Example Scenarios

Comment: Numerous commenters provided recommendations, clarifications, and suggestions ''where inert gas or other vent gas streams which may lower the NHV of the combined stream are added.'' One commenter cited the proposed regulatory text at 40 CFR 60.5417b(d)(8)(ii) to describe the inert gas added scenarios under which NHV continuous monitoring or alternative sampling demonstration would be required, noting that the corresponding language was proposed for EG OOOOc.[124] The commenter provided the following recommendations and supporting rationale for both subparts (NSPS OOOOb and EG OOOOc): (1) remove ''vent streams from storage vessel with high water content,'' (2) ''vent streams from glycol dehydrator unit reboilers'' should be revised to ''vent streams from glycol dehydrator unit reboilers without water removal'' and (3) ''vent streams from enhanced oil recovery facilities'' should be revised to ''vent stream containing water or CO_2 used for enhanced oil recovery.''

The commenter stated that the EPA's intent was to require NHV monitoring when the higher water content from a storage vessel could lower the vent gas NHV below the applicable minimum, but the proposed regulatory language could be interpreted as any produced water tank. The commenter noted that the EPA cites GPA Midstream's comment letter as the basis for this example, though GPA Midstream's letter states that even in these cases, the NHV remained above the applicable limit.[125] The commenter contended that the LP NHV dataset also supports removing ''storage vessel with high water content'' since all data points from produced water tanks were greater than 300 Btu/scf, which meets the minimum vent gas NHV requirement for unassisted, steam-assisted, and air-assisted control devices. While vent streams from produced water tanks can be lower than 900 Btu/scf in certain scenarios, the commenter stated that they are not typically routed to pressure-assisted control devices (minimum vent gas NHV of 800 Btu/scf), since produced water tanks operate at near atmospheric pressure.

The commenter also requested that ''[v]ent streams from glycol dehydrator unit reboilers'' be revised to ''vent streams from glycol dehydrator unit reboilers without water removal'', to be consistent with the preamble. The commenter explained that vent streams from glycol dehydrator unit reboilers have higher water content which lowers the NHV, but they are typically routed through a condenser or other similar equipment to remove water before being routed to combustion control. According to the commenter, the Agency should only require NHV monitoring in cases where the glycol dehydrator unit reboiler does not have water removal.

Finally, the commenter requested that ''[v]ent streams from enhanced oil recovery facilities'' be revised to ''vent stream containing water or CO_2 used for enhanced oil recovery'' to clarify that only vent streams that contain the inert gas involved in EOR, not any vent stream at an EOR site, should require NHV monitoring. According to the commenter, based on process knowledge, operators are able to identify which vents streams at an EOR site contain the inert gas used in EOR and therefore have lower NHV and should be subject to NHV monitoring.

Another commenter agreed that the universe of low-NHV streams identified in the proposal encompasses the scenarios of which they are aware, except the commenter is unclear what the EPA means by ''vent streams from storage vessels with high water content.'' [126] The commenter explained that the proposed language may include crude oil or condensate tanks that share a closed vent system and control device with produced water tanks. The commenter stated that the data they provided includes such tanks systems and shows that low-NHV is not an issue in these systems, given the relatively high NHV of the hydrocarbon components of storage tank vapors. The commenter requested that the EPA not include these storage tank systems in the list of low-NHV scenarios.

Moreover, the commenter asserted that methane, the lightest hydrocarbon organic molecule in process streams at oil and gas facilities, is already above the minimum NHV required for these pressure-assisted devices. Therefore, when a process stream includes any quantities of heavier hydrocarbons, the stream will have a higher heat content and be even further above the minimum NHV requirement. The commenter contended that the EPA's assertion that ''it is easier'' for the streams going to these devices to experience a decrease in NHV is not based on direct or empirical evidence in the rulemaking record. According to the commenter, if inert gases are not added to the hydrocarbon process stream sent to the control device, the NHV will meet the requirements at all times. As with the proposed requirements for non-assisted flares and ECD, the commenter stated that pressure-assisted devices should be assumed to meet minimum NHV requirements. As such, the commenter

[123] 87 FR 74793 (December 6, 2022).

[124] Document ID No. EPA–HQ–OAR–2024–0358–0083.

[125] GPA Midstream—EPA 06/24/24 Meeting Follow-Up. Re: Response to EPA Request for Additional Information Regarding OOOOb GPA Midstream Net Heating Value Case Scenarios and Data. (Attachment Summarizing NHV Data Included).

[126] Document ID No. EPA–HQ–OAR–2024–0358–0088.

suggested that the EPA treat pressure-assisted devices in the same manner as non-assisted flares and ECD and ''require NHV monitoring only in cases where inert gases are added, or for other miscellaneous scenarios which decrease the NHV content of the inlet stream gas to the enclosed combustion device or flare.''

The same commenter also stated that infrequent nitrogen purges should not prevent a flare from qualifying for the NHV testing exemption. The commenter explained that many gas processing facilities within the industry use nitrogen purging during maintenance procedures to displace air or other gases within a system and create an inert environment by removing oxygen and other potentially reactive components which is crucial for safety, preventing unwanted chemical reactions within pipelines and equipment, and reducing emissions by avoiding potential leaks. The commenter also explained that facilities typically perform nitrogen purging no more than one to three times a year and these purges are small in volume relative to the overall flow going to a flare or ECD. Thus, the commenter reported that they do not expect nitrogen purging to have an impact significant enough to lower the NHV to levels below the compliance limits.

The same commenter additionally suggested that the EPA allow the NHV monitoring exemption when intermittent nitrogen purging occurs in volumes that will not significantly impact the NHV of the total gas stream going to the flare. The commenter stated that the EPA should include an option to demonstrate compliance using site-specific data and process knowledge, such as nitrogen purge volumes and total volume sent to the control device, in the rule language to allow the owner/operator to continue using the NHV monitoring exemption by documenting that intermittent nitrogen purging did not result in the NHV of the total gas stream going to the control device decreasing below the compliance limits.

Conversely, a commenter agreed with the EPA's proposal to not exclude pressure-assisted flares and ECD from NHV demonstration requirements.[127] The commenter asserted that this is the only lawful and rational approach given the Agency's prior findings that the required minimum NHV of 800 Btu/scf for pressure-assisted control devices is not significantly higher than the NHV of methane, that sources that contain primarily methane would not require much dilution from inert components to be below the 800 Btu/scf NHV threshold, and that, while data provided by petitioners indicated that the majority of samples had NHVs above 800 Btu/scf, it is much easier for the NHV in the vent gas samples from these control devices to decrease and approach the 800 Btu/scf NHV threshold.

Response: The EPA appreciates the suggestions and clarifications from the commenters to further expand upon the particular ''miscellaneous scenarios'' that could decrease the NHV content of the of the inlet stream gas to all flare and ECDs for both new and existing sources. Based upon the received comments, as well as those scenarios already included in the January 2025 Proposal, the EPA considers the following miscellaneous operating scenarios as those that could potentially decrease the NHV content of a given inlet stream, and which therefore will not be exempted from the NHV sampling requirements under NSPS OOOOb and EG OOOOc for all flare and ECDs for both new and existing sources, where applicable:

1. Combining AGR system amine regenerator still column vent gas with affected facility vent gas streams—AGR amine regenerator still column vent gases typically are routed to an individual control device due to the low flow rate, low pressure, and corrosive nature of the vent stream, and that the low NHV of the stream typically requires supplemental gas for proper control device operation. However, it is possible to combine the still column vent gas with other vent gas streams, which would lower the NHV of the combined stream, primarily due to the high CO_2 content of the still column vent gas.

2. Combining glycol dehydration unit reboiler vent gas with affected facility vent gas streams without water removal—typically, glycol dehydration unit reboiler vent gas is routed through a condenser to remove liquids (including VOC and water vapor) and then routed to a process or control device. However, it is possible to combine the glycol dehydration unit reboiler gas, without routing through a condenser, with other vent gases routed to common control. The high water content of the reboiler vent gas stream could lower the NHV of the combined vent gas streams.

3. Use of inert gases and entrainment in affected facility vent gas streams—midstream operations usually do not employ the use of inert gases such as nitrogen because if a blanket gas is needed, its midstream operations use natural gas as it is readily available and compatible with control devices due to the high NHV. In instances where an inert gas such as nitrogen is used as a blanket gas, this could cause lower NHV of the vent gas stream.

4. High water content in vent gas streams from storage vessels—midstream operations employ the use of storage vessels for storing hydrocarbons and produced water (*i.e.,* produced water tanks), which typically have NHVs well above the minimum thresholds required by the March 2024 Final Rule. However, it is possible that some production areas could have higher water content in the vent stream coming from the storage vessels, which would lower the NHV. In these cases, the high water content would increase the probability that the storage vessel emissions thresholds for applicability would not be exceeded. The EPA also clarifies that this scenario pertains to a higher water content from a storage vessel that could lower the NHV below the applicable minimum value, and not ''any produced water tank.'' It is the EPA's understanding that operators have various means of making this determination on an operating history, best engineering judgement, or manufacturer's recommendation basis as a response to known operating scenarios that could lower the NHV below the applicable minimum value.

5. Compressors in acid gas service—also known as sour gas service, these compressors are used to compress gases containing H_2S and CO_2 for various applications, including injection into underground disposal wells, which are in turn used for natural gas processing and the disposal of acid gas components.

6. Sites in fields with vent streams containing water or CO_2 flooding used for EOR.

7. Flares at gas plants that receive acid gas from sweetening units.

8. NRUs—NRUs in the oil and gas industry are used for separating nitrogen from natural gas streams, improving the heating value and marketability of the gas, and meeting pipeline specifications. This is often achieved using cryogenic distillation. However, during the NRU process, nitrogen dilutes the NHV content of the natural gas, making it less efficient.

d. Flare Tip Maximum Velocity Limits

In the January 2025 Proposal, the EPA proposed revisions to 40 CFR 60.5417b(d)(8)(iv), which includes requirements for the usage of one-time assessments in lieu of installing vent gas flow monitors and, in the case of assisted flares, assist gas flow monitors if certain provisions are met. In the March 2024 Final Rule, while we

[127] Document ID No. EPA–HQ–OAR–2024–0358–0086.

finalized provisions requiring owners and operators of unassisted flares to conduct an initial determination to ensure the flare tip velocity falls within limits under worst-case flow provisions, we did not finalize similar ''initial determination'' requirements for air-assisted flares, even though the velocity limits apply. Therefore, we proposed to add this maximum velocity assessment to the existing provisions in 40 CFR 60.5417b(d)(8)(iv)(D) and (E) for air-assisted flares. This provision is not applicable to ECD. In reviewing these provisions, we also noted that there was no corresponding provision for steam-assisted flares or ECD. This was an oversight in the March 2024 Final Rule, and we proposed new provisions at 40 CFR 60.5417b(d)(8)(iv)(F) similar to those for air-assisted devices that are specific to steam-assisted flares or ECD. These revisions are not needed in EG OOOOc because these provisions are specific to evaluations for flares complying with an NHV_{cz} or NHV_{dil} parameter. The EPA solicited comment on these proposed provisions to ensure compliance with the velocity operating limit and whether, for those devices that have conducted NHV demonstrations, the velocity limit used in the assessment should be based on the allowable velocity at the lowest NHV result from the demonstration rather than being based on the default of 18.3 meters/second (60 feet/second).

Comment: For air-assisted flares, several commenters believed that the proposed text for alternatives to inlet flow monitoring at 40 CFR 60.5417(d)(8)(iv) references incorrect flare tip maximum exit velocity limits. One commenter [128] asserted that the maximum flare tip velocity limit should be based on the methodology in 40 CFR 60.18 rather than a default limit of 60 feet/second for alternative flow monitoring demonstrations. The commenter stated that NSPS OOOOb at 40 CFR 60.5412b(a)(3)(v) states that flares (except for pressure-assisted flares) must comply with the maximum flare tip velocity limits in 40 CFR 60.18. The commenter stated that the rule, however, then uses a default maximum tip velocity of 18.3 meters/second (60 feet/second) for the alternative flow monitoring demonstration requirements at 40 CFR 60.5417b(d)(8)(iv)(B)(1) for unassisted devices. The commenter stated that the EPA is proposing to add similar regulatory text for air- and steam-assisted flares at 40 CFR 60.5417b(d)(8)(iv)(D)(3), (E)(3), and (F)(3) in this rulemaking. The commenter indicated that most gas streams in upstream and midstream operations have sufficient minimum NHV to allow maximum tip velocities greater than 60 feet/second in accordance with 40 CFR 60.18.

The commenter further added that they do not believe it was the EPA's intent that when the backpressure regulator is used in lieu of (*i.e.,* as an alternate to) flow monitoring, the flare tip velocity must be maintained below 60 feet/second, as 40 CFR 60.18 allows for higher tip velocities based on NHV. The commenter suggested that the EPA should therefore update the alternative flow monitoring demonstrations requirements to reference the applicable 40 CFR 60.18 requirements for maximum tip velocity rather than use a default of 60 feet/second.

Two commenters explained that while the proposed text requires that the maximum flow rate to the flare should not exceed 18.3 meter/second, this is not the 40 CFR 60.18 standard that applies to air-assisted flares.[129] Instead, the commenter stated, 40 CFR 60.18(c)(5) requires that air-assisted flares ''be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the methods specified in [40 CFR 60.18(f)(6)].'' According to the commenter, using V_{max} provides a much larger acceptable flare operating range without compromising flare performance. The commenter stated that if the EPA does not make this change, the scope of flares subject to this alternative could be significantly reduced, and, in turn, the EPA's assumption that ''few facilities will have to install continuous monitoring systems'' would be incorrect. Another commenter also explained that the NSPS OOOOb proposal text and the March 2024 Final Rule both apply the same maximum exit velocity of 18.3 meter/second to steam-assisted and unassisted flares.[130] The commenter assumed that the EPA derived this limit from 40 CFR 60.18(c)(4)(i), but explained that while they agree that this limit does apply to certain steam-assisted and unassisted flares, multiple limits could apply, depending on the operating conditions. Similarly, another commenter noted that the January 2025 Proposal did not reference or incorporate all of the applicable 40 CFR 60.18(c) provisions for unassisted flares.[131] The commenter requested that, for unassisted flares, the EPA allow operators to demonstrate compliance with any of the options in 40 CFR 60.18(c)(3)(i) or (4). For these reasons, commenters requested that the EPA provide the full suite of options under 40 CFR 60.18 for flare tip exit velocity limits.

One commenter also stated that the corresponding edits should also be made to the EG OOOOc alternative flow monitoring demonstration requirements in 40 CFR 60.5417c(d)(8)(iv)(B)(1).[132]

Conversely, one commenter agreed with the EPA's previous recognition that 40 CFR 60.18(d) mandates the Agency to establish monitoring for 40 CFR 60.18(c)(3)(ii)'s NHV limits, which the March 2024 Final Rule adopted for unassisted flares.[133] [134] The commenter contended that the EPA's proposed exemption from NHV monitoring violates 40 CFR 60.18(d), which requires each applicable subpart to include provisions stating how owners or operators using flares will monitor them.

Response: We agree with the commenters that 40 CFR 60.18(c) and (f) provide alternative values for the maximum flare tip velocity, V_{max}. We included the 18.3 meters/second (60 feet/second) value for V_{max} because it was the lowest V_{max} value for the 40 CFR 60.18 alternatives and because there were exemptions from NHV monitoring, so data may not be available to assess V_{max} using the alternatives in 40 CFR 60.18. However, the exemptions from NHV monitoring are based on data supplied by petitioners and commenters, which show that NHV of gases generated at oil and gas facilities are consistently above 800 Btu/scf, provided no inert gases are added. At these high NHV vent gas values, V_{max} values of up to 122 meters/second (400 feet/second) are allowed. As such, we agree with the commenters that the proposed 18.3 meters/second (60 feet/second) V_{max} limits unnecessarily impose more stringent limitations when the engineering assessment is used to demonstrate compliance. We agree that this could require the installation of flow meters on many flares where, if more accurate estimates of NHV were allowed, the flare could have demonstrated continuous compliance with the V_{max} limit based on the engineering calculations.

We also note that we allow the use of ''. . . the minimum expected value of the NHV of the inlet gas to the enclosed

[128] Document ID No. EPA–HQ–OAR–2024–0358–0083.

[129] Document ID Nos. EPA–HQ–OAR–2024–0358–0088, –0092.

[130] Document ID No. EPA–HQ–OAR–2024–0358–0088.

[131] Document ID No. EPA–HQ–OAR–2024–0358–0092.

[132] Document ID No. EPA–HQ–OAR–2024–0358–0083.

[133] Document ID No. EPA–HQ–OAR–2024–0358–0086.

[134] 87 FR 74702 and 74792–93 (December 6, 2022).

combustion device or flare based on previous sampling results or process knowledge of the streams sent to the enclosed combustion device or flare . . .'' when conducting engineering assessments used to demonstrate compliance with the NHV_{cz} or NHV_{dil} requirements (see 40 CFR 60.5417b(d)(8)(iv)(D)(*2*) and (E)(*2*)). Because we allow the use of previous sampling results or process knowledge for determining minimum NHV in these engineering assessments, we find it is more consistent and reasonable to allow these same provisions in the V_{max} engineering calculations. Therefore, we are revising the engineering assessments related to maximum flare tip velocities to determine V_{max} as specified in the applicable provisions in 40 CFR 60.18(c) and (f) of this chapter using the minimum expected value of the NHV of the inlet gas to the flare or ECD based on previous sampling results or process knowledge of the streams sent to the flare or ECD.

Regarding the 40 CFR 60.18(d) requirement that each applicable subpart include provisions stating how owners or operators using flares will monitor these control devices, the EPA disagrees that these finalized exemptions from the NHV requirements violate 40 CFR 60.18(d), since this final rule is only revising and clarifying the monitoring alternatives in the existing NSPS OOOOb and EG OOOOc rules, rather than removing the monitoring provisions altogether, which will continue to be prescribed and required by 40 CFR 60.5417b and 40 CFR 60.5417c, respectively.

3. Sampling Location and Duration of Alternative Performance Test

In the January 2025 Proposal, the EPA reconsidered the requirements in the March 2024 Final Rule regarding the sampling duration for the alternative performance test (sampling demonstration) option for the NHV compliance demonstration and proposed to allow for shorter sampling times when it is technically infeasible to collect a grab sample for a minimum of one hour. While the March 2024 Final Rule included provisions for sampling periods of longer than 14 days (where needed) to collect a total of 28 samples, and the general provisions in 40 CFR 60.8(b)(5) also allow for ''shorter sampling times and smaller sample volumes when necessitated by process variables or other factors,'' we found compelling the petitioner's arguments and newly presented supporting information regarding the potential instances of intermittent flow of gas streams, which makes sampling for one hour technically infeasible in those cases (*e.g.,* intermittent flow from sources with low pressure). As such, we found it appropriate to propose additional flexibility in the January 2025 Proposal to fully address these intermittent flow situations. Therefore, we proposed that sampling must be conducted for a minimum of one hour, when technically feasible. When it is not technically feasible to collect the sample for a minimum of one hour, the owner or operator should collect the sample for as long as possible, up to one hour. For samples taken during low or intermittent flow events, the owner or operator must document and report the collection time and the reason for not obtaining a full one-hour sample with the NHV sampling results. We requested comment on the actual duration of flow that is achievable in practice for those cases where sampling for one-hour is technically infeasible on low pressure and intermittent gas streams, and why a one-hour sample would be technically infeasible for those cases.

Regarding the location for sampling, we noted that the March 2024 Final Rule required taking a sample of the inlet gas to the control device but did not require that the gas sample be taken directly at the inlet of the control device. We consider an ''inlet gas sample'' to be a sample taken within the control device header system in a location after all vent stream sources have been added to the control device header. While the EPA recognizes petitioners' concerns with installing sampling ports or ''taps'' on these source types, the March 2024 Final Rule does not specify a physical location where the sampling must occur. We therefore do not believe it is necessary to specify that sampling may occur at another ''representative'' location or specify such ''representative'' locations. The EPA also notes that the General Provisions in 40 CFR part 60 include procedures for alternatives to monitoring, including alternative locations for monitoring ''when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements''—these provisions already address site-specific issues with conducting the alternative performance test (sampling demonstration) option.[135] Accordingly, we did not propose to change the current provisions in the March 2024 Final Rule regarding sampling location for the NHV grab sample option.

[135] See footnotes 48 and 49.

a. Sampling Frequency

Comment: One commenter stated that while the EPA proposed revisions to the performance testing requirements, the EPA did not propose amendments to some of the most burdensome requirements (*e.g.,* the sampling frequency of two samples per day for 14 days with an ongoing demonstration of three samples every five years) for the sampling demonstration option for NSPS OOOOb or EG OOOOc, and the one-hour minimum sampling time for the twice daily samples, except in cases where low or intermittent flow makes one-hour sampling infeasible.[136]

Another commenter suggested that sampling using grab samples across multiple days adds useful flexibility and is a sound approach.[137] The commenter appreciated the additional flexibility that the EPA provided in the 14-day sampling process for control devices using grab samples for compliance purposes. The commenter stated that there would not be an expected change in control device vent gas compositions on days when samples could not be taken. As such, they stated that allowing breaks in the 14-day periods for sites that do not use continuous sampling systems would provide representative results at a reduced cost and burden.

One commenter requested that the EPA require only one daily sample for manual grab sampling since two daily samples unnecessarily increases costs and emissions from travel.[138] This commenter asserted that two daily samples are unnecessary, and that the EPA should reduce the requirement to a single daily sample since the vent gas NHV is not expected to vary much between the two samples. The commenter asked the EPA to reduce this unnecessary sampling burden and revise the requirement to one daily sample for a total of 14 total samples.

One commenter stated that if the EPA retains continuous vent gas monitoring requirements for air- and steam-assisted control devices, the commenter supports the EPA's proposal to broaden the use of the 14-day alternative sampling methodology in 40 CFR 60.5417b(d)(8)(iii) to include steam-assisted and premix air-assisted flares and ECD.[139]

Response: The EPA is finalizing the rule to only require a 14-day NHV

[136] Document ID No. EPA–HQ–OAR–2024–0358–0095.

[137] Document ID No. EPA–HQ–OAR–2024–0358–0094.

[138] Document ID No. EPA–HQ–OAR–2024–0358–0083.

[139] Document ID No. EPA–HQ–OAR–2024–0358–0094.

sampling demonstration for certain operating scenarios as summarized in section IV.B.2 of this preamble for all flare and ECDs. These exemptions will significantly reduce the sampling burden of acquiring two samples per day for 14 days. The EPA disagrees that the potential reduced vent gas NHV content for these operating scenarios will not vary much between the two daily samples and is maintaining the two samples per day requirement over a period of 14 days, as currently prescribed by the NSPS OOOOb and EG OOOOc rules.

However, as previously explained in sections III.B and IV.B of this preamble, the EPA is allowing breaks for weekends and holidays which may occur during the 14-day sampling period, such that the 14 days do not have to be consecutive. Consecutive operating days are reasonable for continuous monitoring because these systems are present continuously. However, manual grab sample collection requires someone to be present at the site to collect samples each day, which, if required to be done on consecutive days, would require collection on weekends and potentially on holidays. The March 2024 Final Rule already allows for sampling beyond the 14 days if 28 samples cannot be collected during that timeframe. Allowing additional flexibility for non-consecutive operating day sampling can lengthen the time needed to collect samples and delay the conclusion of the NHV determination, but it does not reduce the number of samples required nor the representativeness of those samples. As such, we consider it reasonable to provide some flexibility in the grab sampling approach to allow twice daily sampling to determine the average NHV of the gas stream for 14 operating days, with no sampling day spaced more than 3 operating days apart from the previous sampling day.

b. Sampling Location and Duration

Comment: Several commenters expressed support for the EPA's proposed revision to allow NHV sampling at a representative location. Specifically, one of the commenters supported the proposed revisions to clarify that NHV sampling may be conducted ''on the inlet gas which is routed to the enclosed combustion device or flare'' to allow NHV sampling to occur at a representative location.[140]

Another commenter stated that the EPA's January 2025 Proposal would require that operators conduct the initial NHV demonstration sampling on ''the inlet gas which is routed to the enclosed combustion device or flare.'' [141] The commenter noted that this may not address their concerns. Specifically, the commenter expressed concern that control devices receiving intermittent flow would require flaring solely for the purpose of collecting samples for NHV analysis. Instead, the commenter suggested the EPA should allow the option to collect samples from the process that can be diverted to a control device, in addition to collecting samples from the piping to the control device. For example, for associated gas control devices, the commenter stated that the operator could collect a sample from the on-pad sales gas system before entering the sales pipeline, rather than having to divert sales gas to a control device to collect a sample from the piping to the control device. In addition, the commenter urged the EPA to allow the collection of NHV samples from representative facilities, and they contended that operators should be allowed to collect representative samples if the sample originates from a representative well site or centralized production facility.

Several commenters stated that the NHV demonstration should allow for ''representative'' grab sampling and that the proposal may not go far enough in allowing this flexibility. One commenter explained that the proposed requirement to conduct sampling at ''the inlet gas which is routed to enclosed combustor or flare'' is unclear, given the EPA's statement that the change ''will clarify that sampling upstream of the inlet to the control device is allowed, provided that the sample is representative of the gas inlet to the control device.'' [142] The commenter stated their concern that ''upstream of the inlet of the control device'' is limiting and that the EPA should allow sampling from anywhere in the process that is representative of the gas that would be routed to the flare. As an example, the commenter described an associated gas process stream that can route to a sales line or a control device and stated that the rule should allow the operator to collect a sample from a location in the process going to the sales line, rather than along the piping or at the inlet to the control device. The commenter explained that, if required to collect the sample from the latter, the operator must divert gas to the flare that would otherwise go to sales, resulting in unnecessary emissions. Further, the commenter stated that if multiple streams route to the control device, it should be necessary only to sample the stream which the operator expects to have the lowest NHV. The commenter stated that the EPA proposed that ''sampling may be conducted from a location on the control device piping header, provided the sampling location is downstream of all waste gas inlets into the header.'' The commenter stated their concern that this suggests that the operator must route all process streams to the control device to collect a sample, downstream of the comingling point; this could require diverting streams to the control device which normally routed to a non-emitting process and would result in additional emissions. The commenter provided as a solution that the EPA allow the operator to sample the process stream with the lowest expected NHV and if that stream is above the applicable NHV limit, it is unnecessary to sample the other, higher NHV streams. Finally, the commenter requested that the final rule allow operators to use samples from nearby, representative facilities that produce from the same reservoir/formation and have similar operating conditions and equipment. The commenter concluded that it is reasonable to expect these facilities to have very similar gas compositions and NHV.

Regarding the minimum one-hour sampling times for collecting NHV samples, several commenters contended that it is unnecessary to conduct one-hour sampling. One of the commenters [143] indicated that the EPA proposes that the collection time for an individual NHV sample may be less than one hour when it is not technically feasible (*e.g.,* low or intermittent), but the collection time must be as long as possible up to one hour. The commenter stated that while the proposed revision partially alleviates their concerns with sampling duration, it does not recognize that a one-hour sample collection time is unnecessary and should be removed. The commenter explained that typical sampling techniques require only a few minutes to collect a valid sample for NHV analysis, regardless of the flow conditions. According to the commenter, collecting or trying to collect a sample for an entire hour is unnecessary to demonstrate compliance with the minimum vent gas NHV requirement since the vent gas NHV of a stream is not expected to vary much within that hour.

[140] Document ID No. EPA–HQ–OAR–2024–0358–0083.

[141] Document ID No. EPA–HQ–OAR–2024–0358–0092.

[142] Document ID No. EPA–HQ–OAR–2024–0358–0088.

[143] Document ID No. EPA–HQ–OAR–2024–0358–0083.

Other commenters stated that one-hour sampling is contrary to the norms of sampling.[144] One commenter noted that while the proposal allows for reduced sampling where it is technically infeasible to conduct a one-hour sample due to LP or intermittent gas flow, which addresses technical infeasibility issues they raised in prior comments, it remains unnecessary to require the collection of a one-hour sample in any event.[145] The commenter requested that the EPA finalize the representative grab sampling revisions that they provided for NSPS OOOOb and include the same revisions in EG OOOOc.

Another commenter stated that for the NHV demonstration in 40 CFR 60.5417b(d)(8)(iii)(A) and (F), the EPA proposes to retain the one-hour minimum sampling time for twice-daily samples, except in cases where sampling for one hour is technically infeasible on LP or intermittent gas streams.[146] The commenter supported allowing an offramp for the one-hour minimum sampling time, and they suggested that the EPA go further and allow the use of representative grab samples for the initial compliance demonstrations requirements, rather than requiring a one-hour sample period.

Conversely, two commenters expressed that they do not support shorter sampling times. More specifically, a sample collected over a specified period of time (*e.g.,* one hour) is considered a composite sample because the sample collected is a ''composite'' of the gases which flowed through the source location over that specified time period, but a grab sample is considered a moment in time.[147] According to one commenter, there is a significant risk that the combination of the allowance for the use of Tedlar bags and the use of the term ''grab sample'' will replace the needed one-hour composite sample with a short duration sample. The commenter reported that over the past year, many samples collected to comply with NSPS OOOOb did not meet the minimum one-hour collection period. The commenter stated that early testing, which attempted to comply more with the one-hour collection periods, resulted in high test failure rates. The commenter asserted that in order to resolve these high test failure rates, without implementing the evacuated containers, heated lines, and other needed sampling system items, industry simply shortened the duration of collection. The commenter stated that industry has shown the compositions and the associated calculated NHVs of the flare/ECD gas will highly vary over the one-hour collection period. Accordingly, the commenter stated, a short duration sample will not be representative of combustion gases. According to the commenter, this issue is further complicated by the EPA's proposal to allow for shorter duration testing as stated in the January 2025 Proposal.

According to the commenter, the industry collected one-hour samples at thousands of flares over the past year, in compliance with NSPS OOOOb and throughout the prior NSPS OOOOa testing. The commenter noted that tests show that the collection of gases has been technically feasible. In cases where the industry has struggled to produce compliant results as a result of collection practices, facility constraints, cost, and existing testing infrastructure the industry has claimed the testing itself is not feasible, cautioned the commenter.

Response: As noted in the January 2025 Proposal, the EPA does not believe it is necessary to specify that sampling may occur at another ''representative'' location or to specify such ''representative'' locations, and we assert that our clarification in the January 2025 Proposal that sampling may be conducted upstream of the inlet to the control device, provided that the sample is representative of the gas inlet to the control device, is sufficient. This is imperative considering that the finalized NHV sampling requirements will entail miscellaneous operating scenarios, where sampling further upstream of the control device (or at ''representative facilities'') would not provide a representative NHV sample. We recognize that some case-by-case determinations may be necessary due to the number of potentially affected sources, and potential operating design configurations. As previously noted in section IV.B.3 of this preamble, the General Provisions in 40 CFR part 60 include procedures for alternatives to monitoring, including alternative locations for monitoring ''when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.'' [148]

Regarding the proposed provision to allow sampling times of less than one hour, the EPA notes that it will still require a minimum one-hour sample duration, except in cases where low or intermittent flow makes one-hour sampling infeasible for both NSPS OOOOb and EG OOOOc sources. The EPA recognizes that NHV content can vary over a given sampling period. However, the EPA also recognizes that industry has demonstrated that there can be some cases where sampling for a minimum period of one-hour may not be physically possible in certain situations. Accordingly, the EPA is allowing less than one-hour sampling times for cases where low or intermittent flow is present, provided that the sampling time used and the reason for the reduced sampling time is documented and reported and that the samples were taken during the period with the lowest expected NHV (*i.e.,* the period with the highest percentage of inerts). While sampling for a period of less than one hour is not considered ideal, the EPA believes that the NHV content during this shorter sampling period should be representative of the NHV content for that particular period of operation, which should also be indicative of the NHV content for that source had a one-hour sample been obtained. In turn, if there is any variance in the NHV content, it would then be reflected in the multiple samples taken over the course of the entire sampling program.

4. Methodologies for Compositional Analysis of the Gas Stream

The EPA reconsidered the requirements in the March 2024 Final Rule that limited the test method for determining the compositional analysis of the gas stream to American Society for Testing and Materials (ASTM) D1945–14 (R2019). The EPA recognizes that other rules in which vent gases are analyzed, such as 40 CFR part 63, NESHAP subpart CC (Refinery MACT)), allow the use of other test methods. In the January 2025 Proposal, the EPA solicited comment to expand the use of similar consensus-based standards (*e.g.,* GPA Midstream 2166 and GPA Midstream 2261) to consider if these additional available methods would alleviate petitioners' concerns that ASTM D1945–14 is not widely available and that testing laboratories do not have the capacity currently to enable its use.

In the January 2025 Proposal, the EPA also proposed to clarify that Tedlar bags may be used to satisfy the grab sampling requirements, provided that the Tedlar bag qualifies as an ''evacuated container'' as prescribed by section

[144] See SPL, Inc., SPL Letter to EPA, 1–2, EPA–HQ–OAR–2024–0358–0038–0032 (March 19, 2024) (''March SPL Letter'').

[145] Document ID No. EPA–HQ–OAR–2024–0358–0088.

[146] Document ID No. EPA–HQ–OAR–2024–0358–0092.

[147] Document ID No. EPA–HQ–OAR–2024–0358–0084, –0096.

[148] See footnotes 48 and 49.

8.2.1.1 of EPA Method 18. We requested comment on the need to clarify that Tedlar bags can be used and the limitation proposed on when Tedlar bags can be used.

Comment: Several commenters suggested that the EPA expand the use of consensus-based standards to those commonly and readily used by the oil and gas industry. These include, but are not limited to, the following:

- Combined Standards API MPMS 14.1 (8th ed.)/GPA 2166 (22)—Collecting and Handling of Natural Gas Samples for Analysis by Gas Chromatography
- GPA 2261—Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography

One commenter stated that this will allow the operators to use the same service providers and laboratories retained for their other operations and ensure adequate capacity.[149] Additionally, these service providers and laboratories have typically been thoroughly vetted and audited by the operators and have been proven to provide accurate and defensible data.

Another commenter remarked that including these consensus-based standards will alleviate concerns that ASTM D1945–14 is not widely available and that testing laboratories do not currently have the capacity to support its use.[150] Furthermore, this commenter contended that ASTM D1945–14 is inappropriate for well sites, centralized production facilities, compressor stations, and gas plants since it evaluates components not typically found in vent gas from these operations (*e.g.,* helium). The commenter noted that concerns expressed about the availability of labs, analysis time, and cost with ASTM D1945–14 have not changed since the commenter submitted its previous reconsideration letter.

One commenter stated that GPA Midstream 2261 is equivalent to ASTM D1495–14D1945 in constituents, has a broader range of heavier hydrocarbons, elutes all gases sequentially without material peak overlap (including nitrogen and methane), meets the regulatory requirements of 40 CFR 60.54717b(d)(8), and employs thermal conductivity detectors.[151] The commenter provided a detailed analysis/rationale for each of these factors in its comment letter.

Several commenters expressed that allowing more test methods would help lab capacity issues but may lead to inconsistent results. One commenter suggested that it is essential to ensure that all approved methods provide equally accurate and precise data.[152]

Regarding Tedlar bags, one commenter suggested that Tedlar bags be excluded from use for the collection of flare gas samples.[153] The commenter explained that Tedlar bags are not designed for the compositions and sampling handling requirements of typical flare gas. The commenter stated that the January 2025 Proposal cites section 8.2.1.1 of EPA Method 18. According to the commenter, EPA Method 18 is not a valid method for the collection and analysis of the gas typically found in flares. Section 1.2.1 of EPA Method 18 states, ''[t]his method is designed to measure gaseous organics emitted from an industrial source. While designed for parts per million (ppm) level sources, some detectors are quite capable of detecting compounds at ambient levels, *e.g.,* ECD, ELCD, and helium ionization detectors.'' The commenter asserted that this method, and its allowed use of Tedlar bags, was designed for ppm level and ambient sources and that it was not designed and validated for percent level gaseous compounds, as found in typical flare gas. According to the commenter, the more appropriate EPA method for the sampling of the typical compositions and compound concentrations found in flare gas is EPA Method 0040, Sampling of Principal Organic Hazardous Constituents from Combustion Sources Using Tedlar Bags. However, the commenter stated that EPA Method 0040 clearly states that Tedlar bags are not applicable for the compounds typically found in flare gas. The commenter stated that hydrocarbon contamination contributed by the Tedlar bag has the potential of distorting the sample and biasing the NHV high. Therefore, the commenter suggested that Tedlar bags be excluded from use for flare gas sampling.

Another commenter recommended that the final rule allow for the use of single cavity stainless steel constant volume cylinders as a vent gas collection method.[154] The commenter stated that the EPA proposed to allow Tedlar bags as an alternative sample collection method. The commenter agreed that alternative sample collection methods are necessary, as Summa canisters are not a good option for vent gas collection. The commenter strongly supported allowing Tedlar bags as an alternative sample collection method. In addition, the commenter requested that the EPA clarify that operators and laboratories may collect grab samples using single cavity stainless steel constant volume cylinders for sample collection, so long as they are maintained according to the requirements set forth in 43 CFR 3175 (Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases; Measurement of Gas).

Several commenters supported the use of Tedlar bags over air sampling canisters primarily due to cost, convenience, and ease of handling. One commenter explained that cleaning canisters is nearly impossible, particularly for rich gas streams (such as those from storage vessels), which leave residuals in canisters and further complicate cleaning and reuse.[155] The commenter explained that the conditioning of Tedlar bags is easier (as they fit easily into standard heating ovens), and Tedlar bags are available in larger quantities per shipment (which makes getting supplies easier).

Response: The EPA acknowledges that allowing additional test methods, especially GPA Midstream 2261 (which was the most cited addition to testing method options), would provide additional flexibility to sources, as well as potential relief to analytical laboratories with substantial backlogs. Since GPA 2261 utilizes the same analytical equipment, including a similar procedure as the existing standard method, and generally provides equivalent results, we are allowing this method as an option (as GPA 2261–19) in the final rule for all sources. For those owners or operators with streams expecting a significant concentration of inert compounds, they should conduct the analysis according to ASTM D1945 or utilize the ''single column method'' in Section 2.1.4 of GPA 2261. Due to the concerns expressed by several commenters about potential issues that could arise from allowing the use of Tedlar bags to satisfy the grab sampling requirements specified by NSPS OOOOb and EG OOOOc, we will not be revising the sample media requirements for canisters currently specified by 40 CFR 60.5413b(d)(5), 60.5417b(d)(8), 60.5413c(d)(5), and 60.5417c(d)(8).

[149] Document ID No. EPA–HQ–OAR–2024–0358–0084.

[150] Document ID No. EPA–HQ–OAR–2024–0358–0083.

[151] Document ID No. EPA–HQ–OAR–2024–0358–0089.

[152] Document ID No. EPA–HQ–OAR–2024–0358–0078.

[153] Document ID No. EPA–HQ–OAR–2024–0358–0084.

[154] Document ID No. EPA–HQ–OAR–2024–0358–0092.

[155] Document ID No. EPA–HQ–OAR–2024–0358–0089.

5. NHV_{cz} and NHV_{dil} for Air- and Steam-Assisted Flares and Enclosed Combustion Devices at Existing and New Sources

In the January 2025 Proposal, the EPA proposed to retain the NHV_{cz} and NHV_{dil} requirements for air- and steam-assisted flares for sources subject to NSPS OOOOb because, as noted in the November 2021 Action (86 FR 63246; November 15, 2021), we had received some data indicating that air- and steam-assisted flares have been found operating outside of the conditions necessary to achieve at least 98 percent control efficiency on a continuous basis. In the January 2025 Proposal, we disagreed with petitioners that these NHV-related parameters are not appropriate for assisted flares in the oil and gas industry, because we had evidence of poor-performing assisted flares in the oil and gas industry. We, therefore, proposed to conclude (as we had in the March 2024 Final Rule) that sufficient evidence exists demonstrating poor destruction efficiencies due to over-assisting a flare or ECD, and thus NHV compliance demonstrations are necessary to show that these particular control devices meet the requisite efficiency. The EPA requested comment on the proposed retention of the NHV_{cz} and NHV_{dil} provisions for new sources. We also requested comment on whether the NHV_{dil} parameter is appropriate for ECD with perimeter assist air and the appropriate effective diameter to use in the calculation of NHV_{dil}, if it is retained, particularly for devices with multiple burner tips within the ECD.

Regarding statements that 40 CFR 60.5417b(d)(8)(iii)(H) appears to not allow alternative test methods to continuously monitor NHV_{cz} and NHV_{dil}, we noted that the provisions at 40 CFR 60.5417b(d)(8)(iii) are specific to the 14-day alternative performance test (sampling demonstration) option and do not apply to continuous monitoring. We did not include provisions for a 14-day demonstration using continuous monitoring of NHV_{cz} and NHV_{dil} because assist rates could be changed and alter the control device's performance. Continuous monitoring using alternative test methods is expressly provided for in 40 CFR 60.5412b(d) and 60.5415b(f)(1)(xi). Additionally, we proposed to clarify in 40 CFR 60.5417b(d)(8)(vi) that continuous monitoring of NHV_{cz} and, if applicable, NHV_{dil} using an approved alternative method as provided under 40 CFR 60.5412b(d)(1)(i) and (ii) is allowed and that, when using this alternative test method, owners and operators are not required to monitor NHV of the vent gas as specified in 40 CFR 60.5412b(d)(8)(ii) or monitor flow rates as specified in 40 CFR 60.5412b(d)(8)(vi) provided they can demonstrate that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed 18.3 meter/second (60 feet/second). The EPA requested comment on the proposed clarifications when using the alternative test method to demonstrate continuous compliance and requested comment on whether and how to use such monitoring as part of the 14-day sampling demonstration.

With respect to the monitoring requirements for NHV_{cz} and NHV_{dil} for air- and steam-assisted flares at new sources, the EPA acknowledged the petitioners' concerns but did not propose significant changes to this requirement for new sources subject to NSPS OOOOb. However, in reviewing these requirements, we noted that the requirements in 40 CFR 60.5417b(d)(8)(vi) reference NHV determinations using the lowest NHV result of the sampling demonstration in 40 CFR 60.5417b(d)(8)(iii), but 40 CFR 60.5417b(d)(8)(iii) does not have provisions for steam-assisted nor for certain air-assisted flares or ECD. Therefore, we proposed to clarify that 40 CFR 60.5417b(d)(8)(iii) can be used for any steam- or air-assisted flare (including perimeter assist air) or ECD, and that the effective vent gas NHV to allow the use of the demonstration is 300 Btu/scf when using continuous 14-day sampling or 360 Btu/scf when using the 14-day grab sampling approach. This revision in 40 CFR 60.5417b(d)(8)(iii) is necessary considering the calculation provision in 40 CFR 60.5417b(d)(8)(vi) and corrects an unintended error in the March 2024 Final Rule. The EPA also requested comment on the use of the proposed use of the 14-day sampling demonstration in 40 CFR 60.5417b(d)(8)(iii) for air- and steam-assisted flares, particularly those at new sources subject to the NHV_{cz} and NHV_{dil} requirements.

With the alternative sampling provisions being proposed in 40 CFR 60.5417b(d)(8)(iii) and the assessments outlined in 40 CFR 60.5417b(d)(8)(iv), we expect that few facilities will need to install continuous monitoring systems. With the monitoring options provided, we considered the costs of the monitoring provisions to be reasonable and necessary to ensure proper operation of these flares at new sources and therefore retain the NHV_{cz} and NHV_{dil} requirements in NSPS OOOOb.

Conversely, the requirement to conduct monitoring for NHV_{cz} and NHV_{dil} at existing sources was included in EG OOOOc in error. The EPA did not conduct Refinery MACT cost level monitoring for existing sources and stated in the preamble to the March 2024 Final Rule that monitoring of NHV_{cz} and NHV_{dil} was not required for existing sources due to concerns about retrofitting existing flares to meet the requirements.[156] The EPA proposed to correct this inadvertent error by removing the requirements to conduct monitoring of NHV_{cz} and NHV_{dil} at existing sources and specifying the requirements for these control systems is an NHV of 300 Btu/scf in the vent gas. The EPA requested comment on the appropriateness of using an NHV of 300 Btu/scf in the vent gas for air- and steam-assisted flares or ECD at existing sources for demonstrating compliance with the combustion efficiency requirements for these control devices.

Comment: The EPA received numerous comments regarding the NHV_{cz} and NHV_{dil} provisions discussed in the January 2025 Proposal, many of which were out-of-scope from the proposal. Regarding the issues for which the EPA specifically requested comment, one commenter[157] noted that for new NSPS OOOOb sources, the EPA proposed to retain the NHV_{cz} and NHV_{dil} requirements, which is already a Refinery MACT requirement. The commenter reminded the EPA that petitioners provided data, experience, and knowledge on why these testing requirements are inappropriate (*e.g.,* non-steady state flow) and are excessively costly ($1 million or more). The commenter requested that the EPA remove this requirement from the proposed rule.

Conversely, one commenter[158] believed the Agency should retain the requirement to monitor NHV_{cz} and NHV_{dil} for air- and steam-assisted flares and ECD at new NSPS OOOOb sources. The commenter agreed with the EPA's statement in the proposed rule that there is sufficient evidence to demonstrate that over-assisting a flare or ECD leads to poor destruction efficiencies, necessitating NHV compliance demonstrations. The commenter also agreed that the NHV_{cz} and NHV_{dil} parameter terms account for the reduction in heating value caused by the introduction of air or steam and that requiring compliance with the NHV_{cz} and NHV_{dil} limits for air- and steam-assisted flares and ECD constitutes BSER under CAA section 111(a)(1).

[156] 89 FR 16895, 16967 (March 8, 2024).

[157] Document ID No. EPA–HQ–OAR–2024–0358–0095.

[158] Document ID No. EPA–HQ–OAR–2024–0358–0086.

Regarding the alternative test method option to demonstrate continuous compliance and whether and how to use such monitoring as part of the 14-day sampling demonstration for air- and steam-assisted flares, particularly those at new sources subject to NHV_{cz} and NHV_{dil} requirements, one commenter [159] stated that although NSPS OOOOb includes provisions for alternate test methods and alternate NHV_{cz} and NHV_{dil} demonstrations in lieu of monitoring, those alternatives may not be feasible for every control device. For example, the commenter stated that OTM–56 can only be used for flares since the Video Imaging Spectral Radiometer (VISR) camera needs a clear view of the flame. The commenter explained that alternate test methods are costly to implement and take time for Agency approval, so they are not an option for immediate compliance and unlikely to be used by small operators. Moreover, the alternate NHV_{cz} and NHV_{dil} demonstrations are problematic given the intermittent operation of control devices at production sites, explained the commenter.

Another commenter [160] urged the EPA to remove the NHV_{cz} and NHV_{dil} requirements for all control devices subject to NSPS OOOOb. The commenter explained that oil and natural gas facilities are fundamentally different than petroleum refineries in that they do not operate at steady state conditions. The commenter explained that this highly variable, non-steady state flow mandates that equipment be sized much larger than ideal steady state conditions and makes flow measurement infeasible. The commenter explained that costs are also an issue, in that upstream facilities do not have the necessary utilities and instrumentation resources that a refinery has, nor do they have instruments that can operate reliably under the varying operating conditions found at oil and natural gas facilities. The commenter added that the alternative NHV_{cz} and NHV_{dil} demonstrations also are problematic, given that the production site does not operate under steady state conditions.

Regarding the appropriateness of using an NHV of 300 Btu/scf in the vent gas for air- and steam-assisted flares or ECD at existing sources for demonstrating compliance with the combustion efficiency requirements for these control devices, one commenter [161] stated that EG OOOOc air- and steam-assist flare vent gas limit of 300 Btu/scf is a reasonable alternative to the NHV_{cz} and NHV_{dil} limits. The commenter supported the flare vent gas limit of 300 Btu/scf as a reasonable alternative to the NHV_{cz} and NHV_{dil} limits in EG OOOOc. The commenter noted that the EPA did not conduct Refinery MACT cost level monitoring for existing sources and stated in the preamble to the March 2024 Final Rule that monitoring of NHV_{cz} and NHV_{dil} was not recommended as part of the EGG for existing sources due to concerns about retrofitting existing flares to meet the requirements.

Response: While some commenters have requested that the removal of NHV_{cz} and NHV_{dil} requirements from NSPS OOOOb, the EPA has made it clear that these monitoring requirements are appropriate and necessary for these types of devices, as there is sufficient evidence to demonstrate that over-assisting a flare or ECD leads to poor destruction efficiencies, necessitating NHV compliance demonstrations (*i.e.,* it is understood that inert gases can be introduced to steam-assisted, air-assisted, and perimeter assist air flares). However, the EPA recognizes that the operation of control devices at oil and natural gas facilities can be fundamentally different than petroleum refineries, which also have NHV_{cz} and NHV_{dil} requirements prescribed under the Refinery MACT. The EPA believes that this final rule, which will impose NHV sampling requirements for only those sources and situations where inert gases are present or under miscellaneous operating scenarios that may lower the NHV of the inlet gas stream, will result in a more manageable monitoring and testing situation industry-wide, and allow the evaluation of certain situations on a case-by-case basis. As previously noted in section IV.B.3 of this preamble, the General Provisions in 40 CFR part 60 include procedures for alternatives to monitoring, including alternative locations for monitoring ‘‘when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements’’.[162]

Based on our analysis of the data submitted by industry, we find that gas streams expected to be routed to a flare or ECD at sites that do not have sources with inerts will have a NHV of well over 800 Btu/scf. At these high NHVs, we expect that facilities will always be compliant with the NHV_{cz} or NHV_{dil} operating limits, even at low flare gas flow rates. Because of the high assurance that these flares or ECD will operate at a high efficiency at all times that vent gas is directed to the devices, we find it reasonable to exempt these flares and ECD from the monitoring and compliance requirements, provided that these devices do not receive streams with inerts that can lower the NHV inlet to the flare or ECD. When inerts are included in the inlet gas stream, it is much more likely that the NHV of the vent gas would fall below 800 Btu/scf and that the NHV_{cz} or NHV_{dil} will fall below the Btu content thresholds. Therefore, we are finalizing the requirement to conduct assessments or monitor NHV and flows to determine continuous compliance with the NHV_{cz} or NHV_{dil} operating limits in cases where inert gases are added or for other miscellaneous scenarios which decrease the NHV_{cz} or NHV_{dil} content of the inlet stream gas to all flare and ECDs for new sources.

The EPA did not receive adverse comments on the proposal to increase the minimum NHV content threshold from 270 to 300 Btu/scf for air- or steam-assisted flares or ECD for existing EG OOOOc sources. Hence, the EPA is finalizing this aspect of the rule as proposed.

The EPA did not receive specific comments on whether the NHV_{dil} parameter is appropriate for ECD with perimeter assist air and the appropriate effective diameter to use in the calculation of NHV_{dil}, particularly for devices with multiple burner tips within the ECD. Hence, the EPA is finalizing these aspects of the rule as proposed.

No additional changes are being made to the NHV_{dil} and NHV_{cz} requirements at this time based upon other comments and suggestions received, which are considered out-of-scope for this rulemaking.

6. Other Miscellaneous Comments on the NHV Provisions

The following subsections describe other miscellaneous provisions of the NSPS OOOOb and EG OOOOc rules that pertain to NHV sampling that the EPA either wishes to address or clarify based upon comments received regarding the January 2025 Proposal.

a. NHV Temperature Basis

In the January 2025 Proposal, the EPA proposed to clarify that the NHV of the vent gas stream must be determined in Btu/scf and not Btu/lb, where the standard condition temperature is 20°C. More specifically, regarding the units in which the NHV is determined as prescribed in the March 2024 Final Rule, we do not disallow the use of

[159] Document ID No. EPA–HQ–OAR–2024–0358–0083.

[160] Document ID No. EPA–HQ–OAR–2024–0358–0088.

[161] Document ID No. EPA–HQ–OAR–2024–0358–0094.

[162] See footnotes 48 and 49.

measurement methods that determine concentrations in terms of weight fractions, but the weight fractions must be converted to volume fractions because the calculations referenced therein from 40 CFR part 63 use Btu/scf, not Btu/lb. Therefore, we did not propose to change the units in the March 2024 Final Rule but rather proposed to clarify that NHV for individual components must be determined in units of Btu/scf consistent with the existing specification using published values of the component NHV per mole at 25°C and one atmosphere and using 20°C as the standard temperature for determining the volume corresponding to one mole of vent gas. We proposed to clarify that since the standard temperature at 40 CFR 60.18(f)(3) is 20°C, the NHV under NSPS OOOOb and EG OOOOc must be determined at this standard temperature. The Agency proposed these clarifications to ensure the NHV determinations are conducted consistently and accurately.

The EPA received only supporting comments on this issue and is finalizing this clarification as proposed.

b. Averaging Periods

In the January 2025 Proposal, the EPA also proposed to clarify that for the purpose of determining the hourly average of the NHV for continuously sampled (*i.e.,* sampled continuously for 14 consecutive days) inlet streams, the hourly average shall be determined on a block (and not a rolling) average. The EPA proposed this clarifying edit to ensure that all owners and operators are using the same averaging timeframe and that it is not left to individual interpretation whether the average should be a block average or a rolling average. Block averages are required for other averaging time periods in the March 2024 Final Rule, and we consider this change to be warranted for consistency and clarity.

The EPA received no comments on this issue and is finalizing this clarification as proposed.

c. Compliance Timing and Deadlines

The EPA also proposed a change to address compliance timing pending the re-evaluation that must occur after a process change that potentially reduces the NHV of the gas sent to an flare or ECD. More specifically for continuous monitoring, which must occur after the results of periodic monitoring indicate the vent stream is not sufficiently above the required NHV, we proposed that continuous monitoring should commence within 60 days after the re-evaluation indicates that the inlet gas stream does not meet the limits. The EPA also proposed to clarify, for both periodic testing and re-evaluations which occur after a process change, that if the results of the grab sampling indicate that the vent stream is not sufficiently above the required NHV, continuous monitoring using a calorimeter, GC, MS, or continuous grab sampling (*i.e.,* once every eight hours) must commence within the specified timeframe.

The EPA received no comments on this issue and is finalizing this clarification as proposed.

V. How do these final amendments impact the implementation of EG OOOOc?

The EPA's final amendments discussed in section III of this preamble will not significantly impact the implementation of EG OOOOc or the State planning process. Based on the EPA's reconsideration, we are finalizing amendments that revise two narrow aspects of the EG: the associated gas temporary flaring provisions for certain situations, and the NHV continuous monitoring and alternative performance test (sampling demonstration) provisions for certain combustion control devices. These final amendments do not alter in any way the EPA's identified BSER in the EG, or the EPA's identified degree of emissions limitation achievable via application of that BSER. Any changes that a State or Tribe may make to their developing plan as a result of this final action will be minor, and the State or Tribe should be able to make such changes before their plans are required to be submitted for approval. The EPA does not anticipate that States will require additional time for State plan submittal solely because of the changes finalized in this rulemaking.

However, after the January 2025 Proposal was published, the EPA published an IFR to extend certain deadlines pertaining to the March 2024 Final Rule in July 2025 and later issued a final rule in December 2025 confirming those amendments and making further changes to the compliance deadlines in the IFR related to NHV monitoring and the initial reporting deadline.[163] Relevant to this discussion, in the IFR, the EPA extended the State plan submittal deadline in EG OOOOc from March 9, 2026, to January 22, 2027.

As indicated in section I.B of this preamble, the issuance of the CAA section 111(d) final EG does not impose binding requirements directly on existing sources. The EG (codified in 40 CFR part 60, subpart OOOOc) applies to States in the development, submittal, and implementation of State plans to establish performance standards to reduce emissions of GHGs from designated facilities (those that were existing sources on or before December 6, 2022). Further, under the TAR, eligible Tribes may seek approval to implement a plan under CAA section 111(d) in a manner similar to a State, and Tribes are authorized under the TAR to develop and implement their own air quality programs, or portions thereof, under the CAA. The response to comments on the January 2025 Proposal on this section of this preamble is in the EPA's RTC document for the final rule.[164]

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders (EO) is available 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 action under E.O. 12866 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. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Economic Impact Analysis for 2025 Oil and Natural gas NSPS & EG Reconsideration,* is available in the docket.

We present the estimated PV and EAV of the estimated cost savings of this final reconsideration in 2024 dollars over the 2024 to 2038 period. The cost savings are represented in this analysis as the reduction in the number of affected sources and a reduction in the number of tests required for each affected source for the changes finalized in this reconsideration. In simple terms, these cost savings are an estimate of the decreased industry expenditures resulting from the final changes to the March 2024 Final Rule requirements. Under this final action, emissions changes and benefits from emission changes were not quantified, nor were

[163] 90 FR 35966 (July 31, 2025) and 90 FR 55671 (December 3, 2025).

[164] Reconsideration of Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. Response to Public Comments on the January 2025, Proposed Rule (90 FR 3734; January 15, 2025).

cost changes from the temporary flaring provisions. Qualitatively, the changes to the temporary flaring limitation could result in cost savings and increases to emissions, while we do not expect any emissions changes to result from the changes to the NHV testing compliance demonstration.

Table 3 presents the estimated cost savings of this proposed action in 2024 dollars for the baseline which includes the March 2024 Final Rule (*i.e.,* the primary baseline analyzed in the EIA).

(*i.e.,* the primary baseline analyzed in the EIA). This table presents the PV and EAV of these estimates discounted at three percent and seven percent.

TABLE 3—PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF COMPLIANCE COST SAVINGS ESTIMATES OF THE FINAL ACTION FROM 2024–2038

[Millions of 2024$]

	3 percent discount rate	7 percent discount rate
Present Value	2,480	1,900
Equivalent Annualized Value	208	209

The analysis, which is contained in the Economic Impact Analysis for this rulemaking, is consistent with E.O. 12866 and is available in the docket for this action.

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 the EPA's analysis of the potential costs and benefits associated with this action.

C. Paperwork Reduction Act (PRA)

OMB has approved the information collection activities contained in this rule under the PRA and has assigned OMB control number 2060–0721 to NSPS OOOOb and EG OOOOc. You can find a copy of the information collection request (ICR) in the docket for this rule, and it is briefly summarized here. The EPA has revised the approved ICR to include small changes to incorporate the EPA's final recordkeeping and reporting to indicate whether the flare or ECD receives inert gases or other streams which may lower the NHV of the combined stream as discussed in section III.B of this preamble. The EPA estimates an average of 48 respondents will be affected by this requirement over the three-year period (2024–2026). The average annual burden for the recordkeeping and reporting requirements for these owners and operators is estimated at 83 person-hours, with an average annual cost of $6,393 (2024$) over the three-year period.

The EPA has also revised the approved ICR to include burden estimates for the maintenance of records associated with the final requirements. Specifically, the EPA includes burden estimates in the revised ICR for the records and annual reporting included in the final rule related to the use of the associated gas extended flaring allowance under ''exigent circumstances'' as specified in section III.A of this preamble. The incremental increase in burden that would be associated with these recordkeeping and reporting requirements relative to the baseline is estimated at two hours per event annually over the three-year period (2024–2026) at an average annual cost of $176 per flaring event over the three-year period. The occurrence of flaring that could potentially be claimed due to ''exigent circumstances'' is unknown. However, we expect that a maximum of 16 percent of flaring events could potentially require an owner or operator to need to extend flaring beyond 72 hours due to ''exigent circumstances.''

The burden associated with the two aforementioned requirements under this final action minimally affects the ICR burden estimated for compliance with EG OOOOc with an estimated annual cost increase of less than one percent for the States. Provided below is a summary of the ICR burden associated with the final notification, recordkeeping and reporting requirements.

Respondents/affected entities: Oil and natural gas owners and operators.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 48.

Frequency of response: Annually.

Total estimated burden: 86 hours per year. Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $6,570 per year (2024$). There are no capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, an ICR 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.

The approved ICR document that the EPA prepared was assigned OMB Control No. 2060–0721 and EPA ICR number 2523.07. You can find a copy of the previously submitted ICR in Docket EPA–HQ–OAR–2021–0317. The revised ICR document that the EPA prepared for this reconsideration final rule has been assigned OMB Control No. 2060–0721 and EPA ICR number 2523.08. You can find a copy of the revised ICR in Docket EPA–HQ–OAR–2024–0358.

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 has reduced net regulatory burden on the small entities subject to the rule. This action addresses two discrete compliance requirement aspects of NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements,[165] providing additional flexibilities to entities subject to the NSPS requirements and to the model rules within EG OOOOc. Specifically, those flexibilities include extending the limitation on temporary flaring from 24 to 72 hours, granting exemptions from monitoring for an expanded number of gas streams due to high NHV content, allowing sampling to be conducted upstream of the control device inlet for operators meeting the NHV compliance demonstration via the alternative performance test, and allowing breaks in performance testing over weekends and holidays during the 14-day period for the performance test option. We have therefore concluded that this action will have reduced net regulatory burden for all directly regulated small entities. For instance, on average, we estimate cost savings of roughly $19,000 per well site due to the changes to the NHV testing provisions across all business size classifications. For further details, see the document, *Economic Impact Analysis for 2025 Oil and Natural Gas NSPS & EG Reconsideration,* in the docket.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C.

[165] The EPA convened a Small Business Advocacy Review (SBAR) Panel prior to the November 2021 Action that was ultimately finalized in the March 2024 Final Rule.

1531–1538 and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any State, local or Tribal governments or the private sector. This action addresses two discrete compliance requirement aspects of NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements.

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. However, the EPA recognizes that States will have a substantial interest in this action and any future revisions to associated requirements. This action addresses two discrete compliance requirement aspects of NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements.

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

This action does not have Tribal implications as specified in E.O. 13175. This action addresses two discrete compliance requirement aspects of NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements. Thus, E.O. 13175 does not apply to this action. However, consistent with the EPA Policy on Consultation with Indian Tribes, the EPA offered consultation to all Federally Recognized Tribes during the development of this action on December 23, 2024. No Tribes requested consultation.

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

The EPA interprets E.O. 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ‘‘covered regulatory action’’ in section 2–202 of the E.O. The EPA believes that it is not practicable to assess whether an environmental health risk or safety risk affecting children may exist prior to this action. This action addresses two discrete compliance requirement aspects of NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements and does not result in any changes to the BSER of NSPS OOOOb or EG OOOOc. The EPA believes that the EPA's Policy on Children's Health also does not apply.

Therefore, this action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk. Since this action does not concern human health, EPA's Policy on Children's Health also does not apply.

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. Further, we have concluded that this action is not likely to have any adverse energy effects because this action addresses two discrete compliance requirement aspects of NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements and does not result in any changes to the BSER of NSPS OOOOb or EG OOOOc.

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

This action does not involve any new technical standards. Therefore, the NTTAA does not apply. In this rule, the EPA is including regulatory text for 40 CFR part 60, subparts OOOOb and OOOOc that includes incorporation by reference. In accordance with requirements of 40 CFR 60.17, the EPA is incorporating the following two standards by reference.

- GPA Standard 2261–19 (GPA 2261–19), Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, (Revised 2019), IBR approval requested for NSPS subpart OOOOb § 60.5417b(d)(8)(ii)(D) and NSPS subpart OOOOc § 60.5417c(d)(8)(ii)(D). This is a method for determining the chemical composition of natural gas and similar gaseous mixtures using a Gas Chromatograph. This method uses a gas chromatograph to separate and quantify hydrocarbons and non-hydrocarbons. This information can be used to calculate the Btu content of the natural gas sample.
- ASTM D1945–14 (Reapproved 2019), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, approved December 1, 2019; IBR approval requested for §§ 60.5417b(d)(8)(ii)(D); 60.5417c(d)(8)(ii)(D). This method covers the determination of the chemical composition of natural gases and similar gaseous mixtures within the range of composition. The method uses gas chromatography to physically separate the component in the sample and compares them against calibration data from a reference standard. This method is used to determine gas properties such as heating value.

The GPA 2261–19 standard is available at the GPA Midstream website at the following location: GPA Midstream Association, 6060 American Plaza, Suite 700, Tulsa, OK 74135; phone: (918) 493–3872; website: *www.gpamidstream.org.* GPA offers memberships or subscriptions that allows access to their methods.

ASTM D1945–14 is available at ASTM International, 1850 M Street NW, Suite 1030, Washington, DC 20036. See *https://www.astm.org/.* This standard is available to everyone at a cost determined by the ASTM ($96). The ASTM also offers memberships or subscriptions that allow unlimited access to their methods. The cost of obtaining these methods is not a significant financial burden, making the methods reasonably available to stakeholders.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit the rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 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 stated in the preamble, the Environmental Protection Agency amends part 60 of title 40, chapter I, of the Code of Federal Regulations as follows:

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)(78) and (m)(5) to read as follows:

* * * * *

(h) * * *

(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); 60.5417b(d); 60.5417c(d).

* * * * *

(m) * * *

(5) GPA Standard 2261–19 (GPA 2261–19), Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, (Revised 2019), IBR approved for §§ 60.4415(a); 60.5417b(d); 60.5417c(d).

* * * * *

Subpart OOOOb—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022

■ 3. Amend § 60.5377b by revising paragraphs (b) through (g) to read as follows:

§ 60.5377b What GHG and VOC standards apply to associated gas wells at well affected facilities?

* * * * *

(b) For associated gas wells that commenced construction between May 7, 2024 and May 7, 2026, you can comply with the requirements in paragraph (f) of this section continually upon startup instead of paragraph (a) of this section until May 7, 2026 if you demonstrate and certify that it is not feasible to comply with paragraphs (a)(1) through (4) of this section due to technical reasons in accordance with paragraph (g) of this section. After May 7, 2026, you must continually comply with paragraph (a) of this section at all times.

(c) For associated gas wells that commenced construction between December 6, 2022, and May 7, 2024, and for associated gas wells that undergo reconstruction or modification after December 6, 2022, you can comply with the requirements in paragraph (f) of this section instead of paragraph (a) of this section if you demonstrate and certify that it is not feasible to comply with paragraphs (a)(1) through (4) of this section due to technical reasons in accordance with paragraph (g) of this section. Associated gas wells that are modified or reconstructed must comply with paragraph (a) or (f) of this section upon startup and at all times thereafter.

(d) If you are complying with paragraph (a) of this section, you may temporarily route the associated gas to a flare or control device that achieves a 95.0 percent reduction in VOC and methane emissions in the situations and for the durations identified in paragraph (d)(1), (2), (3), or (4) of this section. The associated gas must be routed through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the control device must meet the conditions specified in § 60.5412b during the period when the associated gas is routed to the flare. Records must be kept of all instances in which associated gas is temporarily routed to a flare or to a control device in accordance with § 60.5420b(c)(3)(i)(B) and reported in the annual report in accordance with § 60.5420b(b)(4)(i)(B).

(1) During a malfunction or incident that endangers the safety of operator personnel or the public you are allowed to route associated gas to a flare or control device until the malfunction or incident is resolved, but not longer than 72 hours per incident. Temporarily routing associated gas to a flare or control device is allowed only until the malfunction or incident is resolved. Notwithstanding the previous sentences, if there are exigent circumstances that reasonably require routing to a flare or control device for more than 72 hours, paragraphs (d)(1)(i) through (iii) of this section apply.

(i) An ''exigent circumstance'' for purposes of this paragraph (d)(1) is a situation that results in the inability to reasonably access a site with the necessary equipment and personnel to address and resolve incidents that cause the need to temporarily flare associated gas for more than 72 hours. This includes circumstances where there is a need to flare beyond 72 hours due to an unexpected malfunction event and equipment needed to resolve an incident are not readily available due to an owner's or operator's inability to secure the required equipment for reasons beyond an owner's or operator's control (*i.e.,* supply chain issues); or there is a temporary shortage of personnel needed to resolve an incident due to a circumstance such as a declared national pandemic that is beyond the owner's or operator's control.

(ii) Temporarily routing associated gas to a flare or control device is allowed until the malfunction or incident is resolved, but shall not be longer than 72 hours after the site can be accessed following the passing of the exigent circumstance.

(iii) For instances where you route associated gas to a flare or control device for more than 72 hours, you must meet the reporting requirements specified in § 60.5420b(b)(4)(i)(B)(*4*) and must maintain the records specified in § 60.5420b(c)(3)(v).

(2) During repair and maintenance, including blow downs, a production test, or commissioning, you are allowed to route associated gas to a flare or control device until the incident is resolved, but no longer than 72 hours per incident. Temporarily routing associated gas to a flare or control device is allowed only until the incident is resolved. Notwithstanding the previous sentences, if there are exigent circumstances that reasonably require routing to a flare or control device for more than 72 hours, paragraphs (d)(1)(i) through (iii) apply.

(3) For wells complying with paragraph (a)(1) of this section, during a temporary interruption in service from the gathering or pipeline system you are allowed to route to a flare or route to a control device for the duration of the temporary interruption not to exceed 30 days per incident.

(4) During periods when the composition of the associated gas does not meet pipeline specifications for sources complying with paragraph (a)(1) of this section, or when the composition of the associated gas does not meet the quality requirements for use as a fuel for sources complying with paragraph (a)(2) of this section, or when the composition of the associated gas does not meet the quality requirements for another useful purpose for sources complying with paragraph (a)(3) of this section, you are allowed to route to a flare or control device until the associated gas meets the required specifications or for 72 hours per incident, whichever is less.

(e) If you are complying with paragraph (a), (d), or (f) of this section, you may vent the associated gas in the situations and for the durations identified in paragraph (e)(1), (2), or (3) of this section per incident. The cumulative period of venting must not exceed 24 hours for any calendar year. Records must be kept of all venting instances in accordance with § 60.5420b(c)(3)(ii) and reported in the annual report in accordance with § 60.5420b(b)(4)(ii).

(1) For up to 12 hours per incident to protect the safety of personnel.

(2) For up to 30 minutes per incident during bradenhead monitoring.

(3) For up to 30 minutes per incident during a packer leakage test.

(f) You must route the associated gas to a control device that reduces methane and VOC emissions by at least 95.0 percent. The associated gas must be routed through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the control device must meet the conditions specified in § 60.5412b.

(1) For associated gas wells identified in paragraph (b) of this section, you can comply with the requirements in this paragraph (f) for up to a one year period if you demonstrate and certify that it is not feasible to comply with paragraphs (a)(1) through (4) of this section due to technical reasons in accordance with paragraph (g) of this section. This allowance is renewable each year with an updated technical infeasibility demonstration and certification in accordance with paragraph (g) of this section. Associated gas wells identified in paragraph (b) of this section are not allowed to comply with the requirements in this paragraph (f) after May 7, 2026.

(2) For associated gas wells identified in paragraph (c) of this section, you can comply with the requirements in this paragraph (f) for up to a one year period if you demonstrate and certify that it is not feasible to comply with paragraphs (a)(1) through (4) of this section due to technical reasons in accordance with paragraph (g) of this section. This allowance is renewable each year with an updated technical infeasibility demonstration and certification in accordance with paragraph (g) of this section.

(g) For affected sources identified in paragraphs (b) and (c) of this section that are complying with the requirements in paragraph (f) of this section, you must demonstrate that it is not feasible to comply with paragraphs (a)(1) through (4) of this section due to technical reasons by providing a detailed analysis documenting and certifying the technical reasons for this infeasibility.

(1) The demonstration must address the technical infeasibility for all options identified in paragraphs (a)(1) through (4) of this section.

(2) This demonstration must be certified by a professional engineer or another qualified individual with expertise in the uses of associated gas. The following certification, signed and dated by the qualified professional engineer or other qualified individual shall state: ''I certify that the assessment of technical and safety infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared pursuant to the requirements of § 60.5377b(b). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.''

(3) This demonstration and certification are valid for no more than 12 months. You must re-analyze the feasibility of complying with paragraphs (a)(1) through (4) of this section and finalize a new demonstration and certification each year.

(4) Documentation of these demonstrations, along with the certifications, must be maintained in accordance with § 60.5420b(c)(3)(iii) and submitted in annual reports in accordance with § 60.5420b(b)(4)(iii)(C) and (D).

* * * * *

■ 4. Amend § 60.5417b by revising paragraph (c)(1) introductory text, paragraphs (d)(7) and (8), (g)(1), and (i)(6)(v) to read as follows:

§ 60.5417b What are the continuous monitoring requirements for my control devices?

* * * * *

(c) * * *

(1) Except for continuous parameter monitoring systems used to detect the presence of a pilot or combustion flame, each continuous parameter monitoring system must measure data values at least once every hour and record the values for each parameter as required in paragraph (c)(1)(i) or (ii) of this section. Continuous parameter monitoring systems used to detect the presence of a pilot or combustion flame must record a reading at least once every 5 minutes.

* * * * *

(d) * * *

(7) For a combustion control device whose model is tested under § 60.5413b(d), continuous monitoring systems as specified in paragraphs (d)(8)(i) through (iv) and (vi) of this section and visible emission observations conducted as specified in paragraph (d)(8)(v) of this section.

(8) For an enclosed combustion device, other than those listed in paragraphs (d)(1) through (3) and (7) of this section, or for a flare, continuous monitoring systems as specified in paragraphs (d)(8)(i) through (iv) of this section and visible emission observations conducted as specified in paragraph (d)(8)(v) of this section. Additionally, for enclosed combustion devices or flares that are air-assisted or steam-assisted, the continuous monitoring systems specified in paragraph (d)(8)(vi) of this section.

(i) After January 22, 2027, continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.

(ii) Except as provided in this paragraph (d)(8)(ii) and paragraphs (d)(8)(iii) and (vi) of this section, use one of the following methods to continuously determine the NHV of the inlet gas to the enclosed combustion device or flare at standard conditions. If the inlet gas stream to the flare or enclosed combustion device does not include streams from processes or equipment where inert gas or other vent gas streams which may lower the NHV of the combined stream are added (*e.g.,* vent streams from acid gas removal (AGR) system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers without water removal, vent streams from compressors in acid gas service, vent streams containing water or CO_2 used for enhanced oil recovery, vent streams from storage vessels with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV, vent streams from gas plants that receive acid gas from sweetening units, and vent streams from nitrogen removal units (NRU)), the NHV of the inlet stream is considered to be sufficiently above the minimum required NHV for the inlet gas, and you are not required to conduct the continuous monitoring in this paragraph (d)(8)(ii) of this section or the demonstration in paragraph (d)(8)(iii) of this section, but you must submit the report in § 60.5420b(b)(11)(v)(I) and maintain the record in § 60.5420b(c)(11)(vi) indicating that the flare or enclosed combustion device does not receive inert gases or other vent gas streams which may lower the NHV of the combined stream.

(A) A calorimeter with a minimum accuracy of ±2 percent of span.

(B) A gas chromatograph that meets the requirements in paragraphs (d)(8)(ii)(B)(*1*) through (*5*) of this section.

(*1*) You must follow the procedure in Performance Specification 9 of appendix B of this part, except that a single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C). Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to National Institute of Standards and Technology (NIST) standards.

(*2*) You must meet the accuracy requirements in Performance Specification 9 of appendix B of this part.

(*3*) You must use a calibration gas or multiple gases that includes the compounds that are reasonably expected to be present in the flare gas stream. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. You may only use the compounds used to calibrate the gas chromatograph in the calculation of the vent gas NHV.

(*4*) In lieu of the calibration gas described in paragraph (d)(8)(ii)(B)(*3*) of this section, you may use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. Use the response factor for the nearest normal hydrocarbon (*i.e.,* n-alkane) in the calibration mixture to quantify unknown components detected in the analysis. Use the response factor for n-pentane to quantify unknown components detected in the analysis that elute after n-pentane.

(*5*) To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use any published values for the net heating value per mole at 25 °C and 1 atmosphere and use 20 °C as the standard temperature for determining the volume corresponding to one mole of vent gas.

(C) A mass spectrometer that meets the requirements in paragraphs (d)(8)(ii)(C)(*1*) through (*6*) of this section.

(*1*) You must meet applicable requirements in Performance Specification 9 of appendix B of this part for continuous monitoring system acceptance including, but not limited to, performing an initial multi-point calibration check at three concentrations following the procedure in Section 10.1. A single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C). Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to NIST standards.

(*2*) The average instrument calibration error (CE) for each calibration compound at any calibration concentration must not differ by more than 10 percent from the certified cylinder gas value. The CE for each component in the calibration blend must be calculated using the following equation:

Equation 1 to Paragraph (d)(8)(ii)(C)(*2*)

$$CE = \frac{C_m - C_a}{C_a} \times 100$$

Where:

C_m = Average instrument response (ppm).
C_a = Certified cylinder gas value (ppm).

(*3*) You must use a calibration gas or multiple gases that includes the compounds that are reasonably expected to be present in the flare gas stream. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. You may only use the compounds used to calibrate the mass spectrometer in the calculation of the vent gas NHV.

(*4*) In lieu of the calibration gas described in paragraph (d)(8)(ii)(C)(*3*) of this section, you may use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. For unknown gas components that have similar analytical mass fragments to calibration compounds, you may report the unknowns as an increase in the overlapped calibration gas compound. For unknown compounds that produce mass fragments that do not overlap calibration compounds, you may use the response factor for the nearest molecular weight hydrocarbon in the calibration mix to quantify the unknown component. You may use the response factor for n-pentane to quantify any unknown components detected with a higher molecular weight than n-pentane.

(*5*) You must perform an initial calibration to identify mass fragment overlap and response factors for the target compounds.

(*6*) To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use any published value for the net heating value per mole at 25 °C and 1 atmosphere and use 20 °C as the standard temperature for determining the volume corresponding to one mole of vent gas.

(D) A grab sampling system capable of collecting an evacuated canister sample for subsequent compositional analysis at least once every eight hours. Subsequent compositional analysis of the samples must be performed according to ASTM D1945–14 (R2019) or alternatively GPA 2261–19 (incorporated by reference, see § 60.17). To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use any published value for the net heating value per mole at 25 °C and 1 atmosphere and use 20 °C as the standard temperature for determining the volume corresponding to one mole of vent gas.

(iii) As an alternative to the continuous composition monitoring requirements in paragraph (d)(8)(ii) of this section, a sampling demonstration may be used as specified in this paragraph. Flares or enclosed combustion devices that are not required to monitor flare gas composition because the inlet gas streams to the flare or enclosed combustion device does not include streams from processes or equipment where inert gas or other vent gas streams which may lower the NHV of the combined stream are added (*e.g.,* vent streams from acid gas removal (AGR) system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers without water removal, vent streams from compressors in acid gas service, vent streams containing water or CO_2 used for enhanced oil recovery, vent streams from storage vessels with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV, vent streams from gas plants that receive acid gas from sweetening units, and vent streams from nitrogen removal units (NRU)), are not required to conduct sampling demonstrations specified in this paragraph. For an unassisted or pressure-assisted flare or enclosed combustion device, if you demonstrate according to the methods described in paragraphs (d)(8)(iii)(A) through (F) of this section that the NHV of the inlet gas to the enclosed combustion device or flare consistently exceeds the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B) or (C), continuous monitoring of the NHV is not required, but you must conduct the ongoing sampling in paragraph (d)(8)(iii)(G) of this section. For flares and enclosed combustion devices that use assist air (including perimeter assist air) or assist steam, if you demonstrate according to the methods described in paragraphs (d)(8)(iii)(A) through (F) of this section that the NHV of the inlet gas to the enclosed combustion device or flare consistently exceeds 300 Btu/scf, continuous monitoring of the NHV is not required, but you must conduct the ongoing sampling in paragraph (d)(8)(iii)(G) of this section. For an unassisted or pressure-assisted flare or enclosed combustion device, in lieu of conducting the demonstration outlined in paragraphs (d)(8)(iii)(A) through (D) of this section, you may conduct the demonstration outlined in paragraph (d)(8)(iii)(H) of this section, but you must still comply with paragraphs (d)(8)(iii)(E) through (G) of this section.

(A) Continuously monitor the inlet stream which is routed to the flare or enclosed combustion device for 14 operating days or collect a sample of the inlet gas which is routed to the enclosed combustion device or flare twice daily to determine the average NHV of the gas stream for 14 operating days with no sampling day to be spaced more than 3 operating days apart from the previous sampling day. If you do not continuously monitor the NHV, the minimum time of collection for each individual sample be at least one hour when technically feasible. When it is not technically feasible to collect individual samples for at least one hour (*e.g.,* low or intermittent flow), the collection time must be as long as possible up to one hour. For samples taken during low or intermittent flow events, the collection time and the reason for not obtaining a full one hour sample must be documented and reported with the NHV sampling results. Samples must be separated by at least 6 hours. If inlet gas flow is intermittent such that there are not at least 28 samples over the 14 operating day period, you must continue to collect samples of the inlet gas beyond the 14 operating day period until you collect a minimum of 28 samples.

(B) If you collect samples twice per day, count the number of samples where the NHV value is less than 1.2 times the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), (C), or this paragraph (d)(8)(iii) (*i.e.,* values that are less than 240, 360, or 960 Btu/scf, as applicable) during the sample collection period in paragraph (d)(8)(iii)(A) of this section.

(C) If you continuously sample the inlet stream for 14 days, count the number of hourly block average (*e.g.,* noon to 1 p.m., 1 p.m. to 2 p.m., etc.) NHV values that are less than the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), § 60.5415b(f)(1)(vii)(C), or this paragraph (d)(8)(iii) (*i.e.,* values that are less than 200, 300, or 800 Btu/scf, as applicable), during the sample collection period in paragraph (d)(8)(iii)(A) of this section.

(D) If there are no samples counted under paragraph (d)(8)(iii)(B) of this section or there are no hourly block average values counted under paragraph (d)(8)(iii)(C) of this section, the gas stream is considered to consistently exceed the applicable NHV operating limit and on-going continuous monitoring is not required.

(E) If process operations are revised that could reduce the NHV of the gas sent to the enclosed combustion device or flare, such as the removal or addition of process equipment, and at any time the Administrator requires, re-evaluation of the gas stream must be performed according to paragraphs (d)(8)(iii)(A) through (D) of this section within 60 days of the revisions to process operations to ensure the gas stream still consistently exceeds the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), (C)(*1*), or this paragraph (d)(8)(iii). If any of the samples counted under paragraph (d)(8)(iii)(B) of this section or any hourly block average values counted under paragraph (d)(8)(iii)(C) of this section are less than the limits in the respective paragraph you must conduct the continuous monitoring required by one of the options paragraphs (d)(8)(ii)(A) through (D) of this section within 60 days of the re-evaluation of the gas stream.

(F) When collecting samples under paragraph (d)(8)(iii)(A) of this section, the owner or operator must account for any sources of inert gases or other vent gas streams which may lower the NHV of the combined stream (*e.g.,* vent streams from AGR system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers, vent streams from compressors in acid gas service, vent streams from enhanced oil recovery facilities, or vent streams from storage vessel with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV) that can be sent to the enclosed combustion device or flare. The owner or operator must document in the report in § 60.5420b(b)(11)(v)(I) and the records in § 60.5420b(c)(11)(vi) must note the operating scenario(s) which may lower the NHV of the combined stream through the introduction of inert gases or other vent gas streams, and whether the sampling included periods where the highest percentage of inert gases or other vent gas streams which may lower the NHV of the combined stream were sent to the enclosed combustion device or flare. If the introduction of inerts or other vent gas streams which may lower the NHV of the combined stream is intermittent and does not occur during the initial demonstration, the introduction of inerts or other vent gas streams which may lower the NHV of the combined stream will be considered a revision to process operations that triggers a re-evaluation under paragraph (d)(8)(iii)(E). If conditions at the site did not allow sampling during periods where the introduction of inert gases or other vent gas streams which may lower the NHV of the combined stream was at the highest percentage possible, increasing the percentage of inerts will be considered a revision to process operations that triggers a re-evaluation under paragraph (d)(8)(iii)(E).

(G) You must collect three samples of the inlet gas to the enclosed combustion device or flare at least once every 5 years. The minimum time of collection for each individual sample must be at least one hour, when technically feasible. When it is not technically feasible to collect individual samples for at least one hour (*e.g.,* low or intermittent flow), the collection time must be as long as possible up to one hour. For samples taken during low or intermittent flow events, the collection time and the reason for not obtaining a full one hour sample must be documented and reported with the NHV sampling results. The samples must be taken during the period with the lowest expected NHV (*i.e.,* the period with the highest percentage of inerts or other vent gas streams which may lower the NHV of the combined stream). The first set of periodic samples must be taken, or continuous monitoring commenced, no later than 60 calendar months following the last sample taken under paragraph (d)(8)(iii)(A) of this section. Subsequent periodic samples must be taken, or continuous monitoring commenced, no later than 60 calendar months following the previous sample. If any sample taken in accordance with this paragraph (d)(8)(iii)(G) has an NHV value less than 1.2 times the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), (C), or this paragraph (d)(8)(iii) (*i.e.,* values that are less than 240, 360, or 960 Btu/scf, as applicable), you must conduct the continuous monitoring required by one of the options in paragraphs (d)(8)(ii)(A) through (D) of this section within 60 days of receipt of the last sample.

(H) You may request an alternative test method under § 60.5412b(d) to demonstrate that the flare or enclosed combustion device reduces methane and VOC in the gases vented to the device by 95.0 percent by weight or greater. You must use an alternative test method that demonstrates compliance with the combustion efficiency limit; you may not use an alternative test method that demonstrates compliance with NHV_{cz} and NHV_{dil} in lieu of measuring combustion efficiency directly. You must measure data values at the frequency specified in the alternative test method and conduct the quality assurance and quality control requirements outlined in the alternative test method at the frequency outlined in the alternative test method. You must monitor the combustion efficiency of the flare continuously for 14 days. If there are no values of the combustion efficiency measured by the alternative test method that are less than 95.0 percent, the gas stream is considered to consistently exceed the applicable NHV operating limit, and you are not required to continuously monitor the NHV of the inlet gas to the flare or enclosed combustion device.

(iv) Except as noted in paragraphs (d)(8)(iv)(A) through (F) and (vi) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustion device or flare. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as inlet line pressure, line size, and burner nozzle dimensions, to satisfy this requirement. The monitoring instrument must have an accuracy of ±10 percent or better at the maximum expected flow rate.

(A) Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(B) Unassisted flares are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you meet the conditions in paragraphs (d)(8)(iv)(B)(*1*) and (*2*) of this section.

(*1*) You must demonstrate, based on the maximum potential pressure of units manifolded to the flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed the maximum tip velocity as specified in the applicable provisions in § 60.18(c) and (f) of this chapter. You must use the minimum expected value of the NHV of the inlet gas to the flare or enclosed combustion based on previous sampling results or process knowledge of the streams sent to the enclosed flare of combustion device in your demonstration. If there are changes to the process or control device that can be reasonably expected to increase the maximum flow rate to the flare, you must conduct a new demonstration to determine whether the maximum flow rate to the flare is compliant with the applicable maximum flare tip velocity provisions in § 60.18(c) and (f) of this chapter.

(*2*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(C) Unassisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you meet the conditions in paragraphs (d)(8)(iv)(C)(*1*) and (*2*) of this section.

(*1*) You must demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustion device and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustion device cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section to be exceeded. If there are changes to the process or control device that can be reasonably expected to impact the maximum flow rate to the enclosed combustion device, you must conduct a new demonstration to determine whether the maximum flow rate to the enclosed combustor is less than the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section.

(*2*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(D) Air-assisted flares or enclosed combustion devices that use only perimeter assist air and have no assist steam or premix assist air are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device or the flow of assist air if you meet the conditions in paragraphs (d)(8)(iv)(D)(*1*) through (*3*) of this section, as applicable. For these flares and enclosed combustion devices, NHV_{cz} is assumed to be equal to the vent gas NHV.

(*1*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(*2*) If you are required to monitor vent gas composition for the flare or enclosed combustion device according to paragraph (d)(8)(ii) or (iii) of this section, you must demonstrate, based on the maximum flow rate of perimeter assist air to the enclosed combustion device or flare and applicable engineering calculations, that the NHV_{dil} can never be less than the minimum required NHV_{dil}. The demonstration must clearly document why the maximum flow rate of perimeter assist air will never exceed the rate used in the demonstration. You must use the minimum flow rate of vent gas allowed by your backpressure regulator valve and the minimum expected value of the NHV of the inlet gas to the enclosed combustion device or flare based on previous sampling results or process knowledge of the streams sent to the enclosed combustion device or flare in your demonstration. You must update this demonstration if there are changes to the backpressure regulator valve, the backpressure regulator valve set point, or the maximum flow rate of perimeter assist air. You must also update this demonstration if any sampling results of the NHV of the inlet gas to the enclosed combustion device or flare under paragraph (d)(8)(ii) or (iii) of this section are lower than the NHV vent gas value used in your demonstration.

(*3*) For air-assisted flares, you must also demonstrate, based on the maximum potential pressure of units manifolded to the flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed the maximum tip velocity as specified in the applicable provisions in § 60.18(c) and (f) of this chapter. You must use the minimum expected value of the NHV of the inlet gas to the flare or enclosed combustion based on previous sampling results or process knowledge of the streams sent to the enclosed flare of combustion device in your demonstration. If there are changes to the process or control device that can be reasonably expected to increase the maximum flow rate to the flare, you must conduct a new demonstration to determine whether the maximum flow rate to the flare is compliant with the applicable maximum flare tip velocity provisions in § 60.18(c) and (f) of this chapter.

(E) Air-assisted flares or enclosed combustion devices that use only premix assist air and have no assist steam or perimeter assist air are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device or the flow of assist air if you meet the conditions in paragraphs (d)(8)(iv)(E)(*1*) through (*3*) of this section, as applicable.

(*1*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(*2*) If you are required to monitor vent gas composition for the flare or enclosed combustion device according to paragraph (d)(8)(ii) or (iii) of this section, you must demonstrate, based on the maximum flow rate of premix assist air to the enclosed combustion device or flare and applicable engineering calculations, that the NHV_{cz} will never be less than the minimum required NHV_{cz}. The demonstration must clearly document why the maximum flow rate of premix assist air will never exceed the rate used in the demonstration. You must use the minimum flow rate of vent gas allowed by your backpressure regulator valve in and the minimum expected value of the NHV of the inlet gas to the enclosed combustion device or flare based on previous sampling results or process knowledge of the streams sent to the enclosed combustion device or flare in your demonstration. You must update this demonstration if there are changes to the backpressure regulator valve, the backpressure regulator valve set point, or the maximum flow rate of premix assist air. You must also update this demonstration if any sampling results of the NHV of the inlet gas to the enclosed combustion device or flare under paragraph (d)(8)(ii) or (iii) of this section are lower than the NHV vent gas value used in your demonstration.

(*3*) For air-assisted flares, you must also demonstrate, based on the maximum potential pressure of units manifolded to the flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed the maximum tip velocity as specified in the applicable provisions in § 60.18(c) and (f) of this chapter. You must use the minimum expected value of the NHV of the inlet gas to the flare or enclosed combustion based on previous sampling results or process knowledge of the streams sent to the enclosed flare of combustion device in your demonstration. If there are changes to the process or control device that can be reasonably expected to increase the maximum flow rate to the flare, you must conduct a new demonstration to determine whether the maximum flow rate to the flare is compliant with the applicable maximum flare tip velocity provisions in § 60.18(c) and (f) of this chapter.

(F) Steam-assisted flares or enclosed combustion devices that have no premix assist air and or perimeter assist air (other than perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter of the flare tip is 9 inches or greater) are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device or the flow of assist steam if you meet the conditions in paragraphs (d)(8)(iv)(F)(*1*) through (*3*) of this section, as applicable.

(*1*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(*2*) If you are required to monitor vent gas composition for the flare or enclosed combustion device according to paragraph (d)(8)(ii) or (iii) of this section, you must demonstrate, based on the maximum flow rate of assist steam to the enclosed combustion device or flare and applicable engineering calculations, that the NHV_{cz} will never be less than the minimum required NHV_{cz}. The demonstration must clearly document why the maximum flow rate of assist steam will never exceed the rate used in the demonstration. You must use the minimum flow rate of vent gas allowed by your backpressure regulator valve in and the minimum expected value of the NHV of the inlet gas to the enclosed combustion device or flare based on previous sampling results or process knowledge of the streams sent to the enclosed combustion device or flare in your demonstration. You must update this demonstration if there are changes to the backpressure regulator valve, the backpressure regulator valve set point, or the maximum flow rate of assist steam. You must also update this demonstration if any sampling results of the NHV of the inlet gas to the enclosed combustion device or flare under paragraph (d)(8)(ii) or (iii) of this section are lower than the NHV vent gas value used in your demonstration.

(*3*) For steam-assisted flares, you must also demonstrate, based on the maximum potential pressure of units manifolded to the flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed the maximum tip velocity as specified in the applicable provisions in § 60.18(c) and (f) of this chapter. You must use the minimum expected value of the NHV of the inlet gas to the flare or enclosed combustion based on previous sampling results or process knowledge of the streams sent to the enclosed flare of combustion device in your demonstration. If there are changes to the process or control device that can be reasonably expected to increase the maximum flow rate to the flare, you must conduct a new demonstration to determine whether the maximum flow rate to the flare is compliant with the applicable maximum flare tip velocity provisions in § 60.18(c) and (f) of this chapter.

(v) Conduct inspections monthly and at other times as requested by the Administrator to monitor for visible emissions from the combustion device using section 11 of Method 22 of appendix A of this part or conduct visible emissions monitoring according to paragraph (h) of this section. The observation period shall be 15 minutes or once the amount of time visible emissions is present has exceeded 1 minute. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period.

(vi) If you use a flare or enclosed combustion device that is air-assisted or steam-assisted and that receives streams from processes or equipment where inert gas or other vent gas streams which may lower the NHV of the combined stream are added (*e.g.,* vent streams from acid gas removal (AGR) system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers without water removal, vent streams from compressors in acid gas service, vent streams containing water or CO_2 used for enhanced oil recovery, vent streams from storage vessels with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV, vent streams from gas plants that receive acid gas from sweetening units, and vent streams from nitrogen removal units (NRU)), you must either meet the applicable requirements in (d)(8)(vi)(A) through (D) of this section or you must use an approved alternative method allowed under § 60.5412b(d)(1)(i) and (ii) to continuously monitor NHV_{cz} and, if applicable, NHV_{dil}. If you elect to continuously monitor NHV_{cz} and, if applicable, NHV_{dil} using an approved alternative method as provided under § 60.5412b(d)(1)(i) and (ii), you are not required to monitor NHV of the vent gas as specified in paragraph (d)(8)(ii) of this section or monitor flow rates as specified in this paragraph (d)(8)(vi) provided you can demonstrate that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed the maximum tip velocity as specified in the applicable provisions in § 60.18(c) and (f) of this chapter. You must use the minimum expected value of the NHV of the inlet gas to the flare or enclosed combustion based on previous sampling results or process knowledge of the streams sent to the enclosed flare of combustion device in your demonstration.

(A) Except as allowed by paragraph (d)(8)(iv)(E) or (F) of this section, you must monitor and calculate NHV_{cz} as specified in § 63.670(m) of this chapter. Additionally, for flares and enclosed combustion devices that use only perimeter assist air and do not use steam assist or premix assist air, the NHV_{cz} is equal to the vent gas NHV. When NHV_{cz} is equal to the vent gas NHV, you are not required to continuously monitor NHV_{cz} if you meet the requirements in paragraph (d)(8)(iii) of this section.

(B) Except as allowed by paragraph (d)(8)(iv)(D) of this section, for each flare using perimeter assist air, you must also monitor and calculate NHV_{dil} as specified in § 63.670(n) of this chapter. If the only assist air provided to the flare or enclosed combustion control device is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, you are only required to comply with the NHV_{cz} limit specified in paragraph (f)(8)(vi)(A) of this section.

(C) Except as allowed by paragraph (d)(8)(iv) of this section, you must monitor the flare vent gas and assist gas as specified in § 63.670(i) of this chapter.

(D) You must determine the flare vent gas net heating value as specified in § 63.670(l) of this chapter using one of the methods specified in paragraph (d)(8)(ii) of this section. Where the phrase ''petroleum refinery'' is used, for purposes of this subpart, it will refer to flares controlling an affected facility under this subpart. If you are not required to continuously monitor the NHV of the inlet gas because you have demonstrated that it consistently exceeds the applicable operating limit as provided in paragraph (d)(8)(iii) of this section, you must use the lowest net heating value measured in the sampling program in paragraph (d)(8)(iii) of this section for the calculations performed in paragraphs (d)(8)(vi)(A) and (B). You must update this value if a subsequent sampling result of the NHV of the inlet gas to the enclosed combustion device or flare under paragraph (d)(8)(iii) of this section is lower than the NHV vent gas value used in your calculations.

* * * * *

(g) * * *

(1) A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is below the applicable limits specified in § 60.5415b(f)(1)(vii)(B)(*1*) through (*4*) and (*6*) or above the limit specified in § 60.5415b(f)(1)(vii)(B)(*5*); or for each flare or enclosed combustion device except for boilers and process heaters meeting the requirements in § 60.5412b(a)(1)(iii) and catalytic vapor incinerators meeting the requirements in § 60.5412b(a)(1)(v), when the heat sensing device indicates that there is no pilot or combustion flame present for any time period. If you use a backpressure regulator valve to maintain the inlet gas flow to an enclosed combustion device or flare above the minimum value, a deviation occurs if the annual inspection finds that the backpressure regulator valve set point is not set correctly or indicates that the backpressure regulator valve does not

fully close when not in the open position.

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■ 5. Amend § 60.5420b by revising paragraphs (a)(4), (b), (c)(3) through (6), (c)(11) through (15), and paragraph (d) to read as follows:

§ 60.5420b What are my notification, reporting, and recordkeeping requirements?

(a) * * *

(4) An owner or operator who commences well closure activities must submit the following notices to the Administrator according to the schedule in paragraphs (a)(4)(i) and (ii) of this section. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well at the well site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983. You must submit notifications in portable document format (PDF) following the procedures specified in paragraph (d) of this section.

(i) You must submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site.

(ii) You must submit a notification of the intent to close a well site 60 days before you begin well closure activities.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (14) of this section following the procedure specified in paragraph (b)(15) of this section. You must submit performance test reports as specified in paragraph (b)(12) or (13) of this section, if applicable. Subject to the exception in the next sentence, the initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410b; subsequent annual reports are due no later than the same date each year as the initial annual report. Notwithstanding the preceding sentence, no annual report is due before November 30, 2026, on or before which date you must submit all annual reports that were due before November 30, 2026, per the timing specified in the preceding sentence; then subsequent annual reports thereafter are due no later than 90 days after the end of each annual compliance period. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (14) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period. You must submit the information in paragraph (b)(1)(v) of this section, as applicable, for your well affected facility which undergoes a change of ownership during the reporting period, regardless of whether reporting under paragraphs (b)(2) through (4) of this section is required for the well affected facility.

(1) The general information specified in paragraphs (b)(1)(i) through (v) of this section is required for all reports.

(i) The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (b)(1)(iv).

(v) Identification of each well affected facility for which ownership changed due to sale or transfer of ownership including the United States Well Number; the latitude and longitude coordinates of the well affected facility in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the information in paragraph (b)(1)(v)(A) or (B) of this section, as applicable.

(A) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator to which you sold or transferred ownership of the well affected facility identified in this paragraph (b)(1)(v).

(B) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator from whom you acquired the well affected facility identified in this paragraph (b)(1)(v).

(2) For each well affected facility that is subject to § 60.5375b(a) or (f), the records of each well completion operation conducted during the reporting period, including the information specified in paragraphs (b)(2)(i) through (xiv) of this section, if applicable. In lieu of submitting the records specified in paragraphs (b)(2)(i) through (xiv) of this section, the owner or operator may submit a list of each well completion with hydraulic fracturing completed during the reporting period, and the digital photograph required by paragraph (c)(1)(v) of this section for each well completion. For each well affected facility that routes all flowback entirely through one or more production separators, only the records specified in paragraphs (b)(2)(i) through (iv) and (vi) of this section are required to be reported. For periods where salable gas is unable to be separated, the records specified in paragraphs (b)(2)(iv) and (viii) through (xii) of this section must also be reported, as applicable. For each well affected facility that is subject to § 60.5375b(g), the record specified in paragraph (b)(2)(xv) of this section is required to be reported. For each well affected facility which makes a claim that the exemption in § 60.5375b(h) was met, the records specified in paragraph (b)(2)(i) through (iv) and (xvi) of this section are required to be reported.

(i) Well Completion ID.

(ii) Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983.

(iii) U.S. Well ID.

(iv) The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production.

(v) The date and time of each attempt to direct flowback to a separator as required in § 60.5375b(a)(1)(ii).

(vi) The date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production.

(vii) The duration (in hours) of flowback.

(viii) The duration (in hours) of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve).

(ix) The duration (in hours) of combustion.

(x) The duration (in hours) of venting.

(xi) The specific reasons for venting in lieu of capture or combustion.

(xii) For any deviations recorded as specified in paragraph (c)(1)(ii) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation.

(xiii) For each well affected facility subject to § 60.5375b(f), a record of the well type (*i.e.,* wildcat well, delineation well, or low pressure well (as defined § 60.5430b)) and supporting inputs and calculations, if applicable.

(xiv) For each well affected facility for which you claim an exception under § 60.5375b(a)(2), the specific exception claimed and reasons why the well meets the claimed exception.

(xv) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, the supporting analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field.

(xvi) For each well affected facility which meets the exemption in § 60.5375b(h), a statement that the well completion operation requirements of § 60.5375b(a)(1) through (3) were met.

(3) For each well affected facility that is subject to § 60.5376b(a)(1) or (2), your annual report is required to include the information specified in paragraphs (b)(3)(i) and (ii) of this section, as applicable.

(i) For each well affected facility where all gas well liquids unloading operations comply with § 60.5376b(a)(1), your annual report must include the information specified in paragraphs (b)(3)(i)(A) through (C) of this section, as applicable.

(A) Identification of each well affected facility (U.S. Well ID or U.S. Well ID associated with the well affected facility) that conducts a gas well liquid unloading operation during the reporting period using a method that does not vent to the atmosphere and the technology or technique used. If more than one non-venting technology or technique is used, you must identify all of the differing non-venting liquids unloading methods used during the reporting period.

(B) Number of gas well liquids unloading operations conducted during the year where the well affected facility identified in (b)(3)(i)(A) had unplanned venting to the atmosphere and best management practices were conducted according to your best management practice plan, as required by § 60.5376b(c). If no venting events occurred, the number would be zero. Other reported information required to be submitted where unplanned venting occurs is specified in paragraphs (b)(3)(i)(B)(*1*) and (*2*) of this section.

(*1*) Log of best management practice plan steps used during the unplanned venting to minimize emissions to the maximum extent possible.

(*2*) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(C) The number of liquids unloading events where unplanned emissions are vented to the atmosphere during a gas well liquids unloading operation where you complied with best management practices to minimize emissions to the maximum extent possible.

(ii) For each well affected facility where all gas well liquids unloading operations comply with § 60.5376b(b) and (c) best management practices, your annual report must include the information specified in paragraphs (b)(3)(ii)(A) through (E) of this section.

(A) Identification of each well affected facility that conducts a gas well liquids unloading during the reporting period.

(B) Number of liquids unloading events conducted during the reporting period.

(C) Log of best management practice plan steps used during the reporting period to minimize emissions to the maximum extent possible.

(D) The number of liquids unloading events during the year that best management practices were conducted according to your best management practice plan.

(E) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(4) For each associated gas well subject to § 60.5377b, your annual report is required to include the applicable information specified in paragraphs (b)(4)(i) through (vi) of this section, as applicable.

(i) For each associated gas well that complies with § 60.5377b(a)(1), (2), (3), or (4) your annual report is required to include the information specified in paragraphs (b)(4)(i)(A) and (B) of this section.

(A) An identification of each associated gas well constructed, modified, or reconstructed during the reporting period that complies with § 60.5377b(a)(1), (2), (3), or (4).

(B) The information specified in paragraphs (b)(4)(i)(B)(*1*) through (*4*) of this section for each incident when the associated gas was temporarily routed to a flare or control device in accordance with § 60.5377b(d).

(*1*) The reason in § 60.5377b(d)(1), (2), (3), or (4) for each incident.

(2) The start date and time of each incident of routing associated gas to the flare or control device, along with the total duration in hours of each incident.

(3) Documentation that all CVS requirements specified in § 60.5411b(a) and (c) and all applicable flare or control device requirements specified in § 60.5412b were met during each period when the associated gas is routed to the flare or control device.

(*4*) For each instance where you route associated gas to a flare or control device beyond 72 hours due to ‘‘exigent circumstances’’ according to § 60.5377b(d)(1) or (2), you must include the record information specified in paragraph (c)(3)(v) of this section in your annual report.

(ii) For all instances where you temporarily vent the associated gas in accordance with § 60.5377b(e), you must report the information specified in paragraphs (b)(4)(ii)(A) through (D) of this section. This information is required to be reported if you are routinely complying with § 60.5377b(a) or (f) or temporarily complying with § 60.5377b(d). In addition to this information for each incident, you must report the cumulative duration in hours of venting incidents and the cumulative VOC and methane emissions in pounds for all incidents in the calendar year.

(A) The reason in § 60.5377b(e)(1), (2), or (3) for each incident.

(B) The start date and time of each incident of venting the associated gas, along with the total duration in hours of each incident.

(C) The VOC and methane emissions in pounds that were emitted during each incident.

(D) The total duration of venting for all incidents in the year, along with the cumulative VOC and methane emissions in pounds that were emitted.

(iii) For each associated gas well that complies with the requirements of § 60.5377b(f) your annual report must include the information specified in paragraphs (b)(4)(iii)(A) through (E) of this section. The information in paragraphs (b)(4)(iii)(A) and (B) of this section is only required in the initial annual report.

(A) An identification of each associated gas well that commenced construction between May 7, 2024, and May 7, 2026. This identification must include the certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(B) An identification of each associated gas well that commenced construction between December 6, 2022, and May 7, 2024. This identification must include the certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(C) An identification of each associated gas well modified or reconstructed during the reporting period that complies by routing the gas to a control device that reduces VOC and methane emissions by at least 95.0 percent. This identification must include the certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(D) For each associated gas well that was constructed, modified or reconstructed in a previous reporting period that complies by routing the gas to a control device that reduces VOC and methane emissions by at least 95.0 percent, a re-certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(E) The information specified in paragraphs (b)(11)(i) through (iv) of this section.

(iv) If you comply with § 60.5377b(f) with a control device, identification of the associated gas well using the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(vi) For each deviation recorded as specified in paragraph (c)(3)(v) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(5) For each wet seal centrifugal compressor affected facility, the information specified in paragraphs (b)(5)(i) through (v) of this section. For each self-contained wet seal centrifugal compressor, Alaska North Slope centrifugal compressor equipped with sour seal oil separator and capture system, or dry seal centrifugal compressor affected facility, the information specified in paragraphs (b)(5)(vi) through (ix) of this section.

(i) An identification of each centrifugal compressor constructed, modified, or reconstructed during the reporting period.

(ii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(4) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) If required to comply with § 60.5380b(a)(2) or (3), the information specified in paragraphs (b)(11)(i) through (iv) of this section, as applicable.

(iv) If complying with § 60.5380b(a)(1) with a control device, identification of the centrifugal compressor with the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(vi) If complying with § 60.5380b(a)(4), (5), or (6) for a self-contained wet seal centrifugal compressor, Alaska North Slope centrifugal compressor equipped with sour seal oil separator and capture system, or dry seal centrifugal compressor requirements, the cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous volumetric flow rate emissions measurement, as applicable, which have elapsed prior to conducting your volumetric flow rate emission measurement or emissions screening.

(vii) A description of the method used and the results of the volumetric emissions measurement or emissions screening, as applicable.

(viii) Number and type of seals on delay of repair and explanation for each delay of repair.

(ix) Date of planned shutdown(s) that occurred during the reporting period if there are any seals that have been placed on delay of repair.

(6) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(6)(i) through (vii) of this section, as applicable.

(i) The cumulative number of hours of operation since initial startup, since May 7, 2024, since the previous volumetric flow rate measurement, or since the previous reciprocating compressor rod packing replacement, as applicable, which have elapsed prior to conducting your volumetric flow rate measurement or emissions screening. Alternatively, a statement that emissions from the rod packing are being routed to a process or control device through a closed vent system.

(ii) If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(5)(i) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(iv) If complying with § 60.5385b(d)(1) or (2), the information in paragraphs (b)(11)(i) through (iv) of this section. If complying by routing emissions to a control device, as required in § 60.5385b(d)(2), the information in paragraph (b)(11)(v) of this section.

(v) Number and type of rod packing replacements/repairs on delay of repair and explanation for each delay of repair.

(vi) Date of planned shutdown(s) that occurred during the reporting period if there are any rod packing replacements/repairs that have been placed on delay of repair.

(vii) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(7) For each process controller affected facility, the information specified in paragraphs (b)(7)(i) through (iii) of this section in your initial annual report and in subsequent annual reports for each process controller affected facility that is constructed, modified, or reconstructed during the reporting period. Each annual report must contain the information specified in paragraphs (b)(7)(iv) through (x) of this section for each process controller affected facility.

(i) An identification of each process controller that is driven by natural gas, as required by § 60.5390b(d), that allows traceability to the records required in paragraph (c)(6)(i) of this section.

(ii) For each process controller in the affected facility complying with § 60.5390b(a), you must report the information specified in paragraphs (b)(7)(ii)(A) and (B) of this section, as applicable.

(A) An identification of each process controller complying with § 60.5390b(a) by routing the emissions to a process.

(B) An identification of each process controller complying with § 60.5390b(a) by using a self-contained natural gas-driven process controller.

(iii) For each process controller affected facility located at a site in Alaska that does not have access to electrical power and that complies with § 60.5390b(b), you must report the information specified in paragraph (b)(7)(iii)(A), (B), or (C) of this section, as applicable.

(A) For each process controller complying with § 60.5390b(b)(1) process controller bleed rate requirements, you must report the information specified in paragraphs (b)(7)(iii)(A)(*1*) and (*2*) of this section.

(*1*) The identification of process controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh.

(*2*) Where necessary to meet a functional need, the identification and demonstration why it is necessary to use a process controller with a natural gas bleed rate greater than 6 scfh.

(B) An identification of each intermittent vent process controller complying with the requirements in paragraph § 60.5390b(b)(2).

(C) An identification of each process controller complying with the requirements in § 60.5390b(b) by routing emissions to a control device in accordance with § 60.5390b(b)(3).

(iv) Identification of each process controller which changes its method of compliance during the reporting period and the applicable information specified in paragraphs (b)(7)(v) through (ix) of this section for the new method of compliance.

(v) For each process controller in the affected facility complying with the requirements of § 60.5390b(a) by routing the emissions to a process, you must report the information specified in (b)(11)(i) through (iii) of this section.

(vi) For each process controller in the affected facility complying with the requirements of § 60.5390b(a) by using a self-contained natural gas-driven process controller, you must report the information specified in paragraphs (b)(7)(vi)(A) and (B) of this section.

(A) Dates of each inspection required under § 60.5416b(b); and

(B) Each defect or leak identified during each natural gas-driven-self-contained process controller system inspection, and the date of repair or date of anticipated repair if repair is delayed.

(vii) For each process controller in the affected facility complying with the requirements of § 60.5390b(b)(2), you must report the information specified in paragraphs (b)(7)(vii)(A) and (B) of this section.

(A) Dates and results of the intermittent vent process controller monitoring required by § 60.5390b(b)(2)(ii).

(B) For each instance in which monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, the date of repair or replacement or the date of anticipated repair or replacement if the repair or replacement is delayed, and the date and results of the re-survey after repair or replacement.

(viii) For each process controller affected facility complying with § 60.5390b(b)(3) by routing emissions to a control device, you must report the information specified in paragraph (b)(11) of this section.

(ix) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(x) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(7)(vi) and (vii) and (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(8) For each storage vessel affected facility, the information in paragraphs (b)(8)(i) through (x) of this section.

(i) An identification, including the location, of each storage vessel affected facility, including those for which construction, modification, or reconstruction commenced during the reporting period, and those provided in previous reports. The location of the storage vessel affected facility shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the methane and VOC emission rate determination according to § 60.5365b(e)(1) for each tank battery that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(7)(iii) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iv) For each storage vessel affected facility constructed, modified, reconstructed, or returned to service during the reporting period complying with § 60.5395b(a)(2) with a control device, report the identification of the storage vessel affected facility with the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(vi) If required to comply with § 60.5395b(b)(1), the information in paragraphs (b)(11)(i) through (iv) of this section.

(vii) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in § 60.5395b(c)(1)(ii), including the date the storage vessel affected facility was removed from service. You must identify each storage vessel that that is removed from service from a storage vessel affected facility during the reporting period as specified in § 60.5395b(c)(2)(iii), including identifying the impacted storage vessel affected facility and the date each storage vessel was removed from service.

(viii) You must identify each storage vessel affected facility or portion of a storage vessel affected facility returned to service during the reporting period as specified in § 60.5395b(c)(4), including the date the storage vessel affected facility or portion of a storage vessel affected facility was returned to service.

(ix) You must identify each storage vessel affected facility that no longer complies with § 60.5395b(a)(3) and instead complies with § 60.5395b(a)(2). You must identify whether the change in the method of compliance was due to fracturing or refracturing or whether the change was due to an increase in the monthly emissions determination. If the change was due to an increase in the monthly emissions determination, you must provide documentation of the emissions rate. You must identify the date that you complied with § 60.5395b(a)(2) and must submit the information in (b)(8)(iii) through (vii) of this section.

(x) You must submit a statement that you are complying with § 60.112b(a)(1) or (2), if applicable, in your initial annual report.

(9) For the fugitive emissions components affected facility, report the information specified in paragraphs (b)(9)(i) through (v) of this section, as applicable.

(i)(A) Designation of the type of site (*i.e.,* well site, centralized production facility, or compressor station) at which the fugitive emissions components affected facility is located.

(B) For the fugitive emissions components affected facility at a well site or centralized production facility that became an affected facility during the reporting period, you must include the date of the startup of production or the date of the first day of production after modification. For the fugitive emissions components affected facility at a compressor station that became an affected facility during the reporting period, you must include the date of startup or the date of modification.

(C) For the fugitive emissions components affected facility at a well site, you must specify what type of well site it is (*i.e.,* single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment).

(D) For the fugitive emissions components affected facility at a well site where during the reporting period you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, you must include the date of the change to status as a wellhead only well site.

(E) For the fugitive emissions components affected facility at a well site where you previously reported under paragraph (b)(9)(i)(D) of this section the removal of all major production and processing equipment and during the reporting period major production and processing equipment is added back to the well site, the date that the first piece of major production and processing equipment is added back to the well site.

(F) For the fugitive emissions components affected facility at a well site where during the reporting period you undertake well closure requirements, the date of the cessation of production from all wells at the well site, the date you began well closure activities at the well site, and the dates of the notifications submitted in accordance with paragraph (a)(4) of this section.

(ii) For each fugitive emissions monitoring survey performed during the annual reporting period, the information specified in paragraphs (b)(9)(ii)(A) through (G) of this section.

(A) Date of the survey.

(B) Monitoring instrument or, if the survey was conducted by AVO methods, notation that AVO was used.

(C) Any deviations from the monitoring plan elements under § 60.5397b(c)(1), (2), and (7), (c)(8)(i), or (d) or a statement that there were no deviations from these elements of the monitoring plan.

(D) Number and type of components for which fugitive emissions were detected.

(E) Number and type of fugitive emissions components that were not repaired as required in § 60.5397b(h).

(F) Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair.

(G) Date of planned shutdown(s) that occurred during the reporting period if there are any components that have been placed on delay of repair.

(iii) For the fugitive emissions components affected facility complying with an alternative fugitive emissions standard under § 60.5399b, in lieu of the information specified in paragraphs (b)(9)(i) and (ii) of this section, you must provide the information specified in paragraphs (b)(9)(iii)(A) through (C) of this section.

(A) The alternative standard with which you are complying.

(B) The site-specific reports specified by the specific alternative fugitive emissions standard, submitted in the format in which they were submitted to the state, local, or Tribal authority. If the report is in hard copy, you must scan the document and submit it as an electronic attachment to the annual report required in this paragraph (b).

(C) If the report specified by the specific alternative fugitive emissions standard is not site-specific, you must submit the information specified in paragraphs (b)(9)(i) and (ii) of this section for each individual site complying with the alternative standard.

(iv) For well closure activities which occurred during the reporting period, the information in paragraphs (b)(9)(iv)(A) and (B) of this section.

(A) A status report with dates for the well closure activities schedule developed in the well closure plan. If all steps in the well closure plan are completed in the reporting period, the date that all activities are completed.

(B) If an OGI survey is conducted during the reporting period, the information in paragraphs (b)(9)(iv)(B)(*1*) through (*3*) of this section.

(*1*) Date of the OGI survey.

(*2*) Monitoring instrument used.

(*3*) A statement that no fugitive emissions were found, or if fugitive emissions were found, a description of the steps taken to eliminate those emissions, the date of the resurvey, the results of the resurvey, and the date of the final resurvey which detected no emissions.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(9)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(10) For each pump affected facility, the information specified in paragraphs (b)(10)(i) through (iv) of this section in your initial annual report and in subsequent annual reports for each pump affected facility that is constructed, modified, or reconstructed during the reporting period. Each annual report must contain the information specified in paragraphs (b)(10)(v) through (ix) of this section for each pump affected facility.

(i) The identification of each of your pumps that are driven by natural gas, as required by § 60.5393b(a) that allows traceability to the records required by paragraph (c)(15)(i) of this section.

(ii) For each pump affected facility for which there is a control device on site but it does not achieve a 95.0 percent emissions reduction, the certification that there is a control device available on site but it does not achieve a 95.0 percent emissions reduction required under § 60.5393b(b)(5). You must also report the emissions reduction percentage the control device is designed to achieve.

(iii) For each pump affected facility for which there is no control device or vapor recovery unit on site, the certification required under § 60.5393b(b)(6) that there is no control device or vapor recovery unit on site.

(iv) For each pump affected facility for which it is technically infeasible to route the emissions to a process or control device, the certification of technically infeasibility required under § 60.5393b(b)(7).

(v) For any pump affected facility which has previously reported as required under paragraphs (b)(10)(i) through (iv) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pump affected facility and the date that the pump affected facility meets one of the change conditions described in paragraph (b)(10)(v)(A), (B), or (C) of this section.

(A) If you install a control device or vapor recovery unit, you must report that a control device or vapor recovery unit has been added to the site and that the pump affected facility now is required to comply with § 60.5393b(b)(2), (3) or (5), as applicable.

(B) If your pump affected facility previously complied with § 60.5393b(b)(2), (3) or (5) by routing emissions to a process or a control device and the process or control device is subsequently removed from the site or is no longer available such that there is no ability to route the emissions to a process or control device at the site, or that it is not technically feasible to capture and route the emissions to another control device or process located on site, report that you are no longer complying with the applicable requirements of § 60.5393b(b)(2), (3), or (5) and submit the information provided in paragraph (b)(10)(v)(B)(*1*) or (*2*) of this section.

(*1*) Certification that there is no control device or vapor recovery unit on site.

(*2*) Certification of the engineering assessment that it is technically infeasible to capture and route the emissions to another control device or process located on site.

(C) If any pump affected facility or individual natural gas-driven pump changes its method of compliance during the reporting period other than for the reasons specified in paragraphs (b)(10)(v)(A) and (B) of this section, identify the new compliance method for each natural gas-driven pump within the affected facility which changes its method of compliance during the reporting period and provide the applicable information specified in paragraphs (b)(10)(ii) through (iv) and (vi) through (viii) of this section for the new method of compliance.

(vi) For each pump affected facility complying with the requirements of § 60.5393b(a) or (b)(1) or (3) by routing the emissions to a process, you must report the information specified in paragraphs (b)(11)(i) through (iv) of this section.

(vii) For each pump affected facility complying with the requirements of § 60.5393b(b)(3) or (5) by routing the emissions to a control device, you must report the information required under paragraphs (b)(11)(i) through (v) of this section.

(viii) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(ix) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(11) For each well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facility which uses a closed vent system routed to a control device to meet the emissions reduction standard, you must submit the information in paragraphs (b)(11)(i) through (v) of this section. For each reciprocating compressor, process controller, pump, storage vessel, or process unit equipment which uses a closed vent system to route to a process, you must submit the information in paragraphs (b)(11)(i) through (iv) of this section. For each centrifugal compressor, reciprocating compressor, and storage vessel equipped with a cover, you must submit the information in paragraphs (b)(11)(i) and (ii) of this section.

(i) Dates of each inspection required under § 60.5416b(a) and (b).

(ii) Each defect or emissions identified during each inspection and the date of repair or the date of anticipated repair if the repair is delayed.

(iii) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416b(a)(4).

(iv) You must submit the certification signed by the qualified professional engineer or in-house engineer according to § 60.5411b(c) for each closed vent system routing to a control device or process in the reporting year in which the certification is signed.

(v) If you comply with the emissions standard for your well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facility with a control device, the information in paragraphs (b)(11)(v)(A) through (L) of this section, unless you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d). If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), the information in paragraphs (b)(11)(v)(A) through (C) and (L) through (P) of this section.

(A) Identification of the control device.

(B) Make, model, and date of installation of the control device.

(C) Identification of the affected facility controlled by the device.

(D) For each continuous parameter monitoring system used to demonstrate compliance for the control device, a unique continuous parameter monitoring system identifier and the make, model number, and date of last calibration check of the continuous parameter monitoring system.

(E) For each instance where there is a deviation of the control device in accordance with § 60.5417b(g)(1) through (3) or (g)(5) through (7) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (*e.g.,* NHV operating limit, lack of pilot or combustion flame, condenser efficiency, bypass line flow, visible emissions), and cause of the deviation.

(F) For each instance where there is a deviation of the continuous parameter monitoring system in accordance with § 60.5417b(g)(4) include the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation.

(G) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test or observation of the video surveillance output, the length of the observation in minutes, and the number of minutes for which visible emissions were present.

(H) If a performance test was conducted on the control device during the reporting period, provide the date the performance test was conducted. Submit the performance test report following the procedures specified in paragraph (b)(12) of this section.

(I) An indication of whether the enclosed combustion device or flare receives inert gases or other vent streams which may lower the NHV of the combined stream, and if so, a description of the operating scenario(s) which may lower the NHV of the combined stream through the introduction of inert gases or other vent gas streams. If a demonstration of the NHV of the inlet gas to the enclosed combustion device or flare was conducted during the reporting period in accordance with § 60.5417b(d)(8)(iii), an indication of whether this is a re-evaluation of vent gas NHV and the reason for the re-evaluation; the applicable required minimum vent gas NHV; if twice daily samples of the vent stream were taken, the number of samples with NHV values that are less than 1.2 times the applicable required minimum NHV, an indication of whether full one hour samples were collected or if shorter sampling times were used, and, if shorter sampling times were used, the collection time(s) used and the reason for not obtaining a full one hour sample; if continuous NHV sampling of the vent stream was conducted, the number of hourly block average NHV values that are less than the required minimum vent gas NHV; if continuous combustion efficiency monitoring was conducted using an alternative test method approved under § 60.5412b(d), the number of values of the combustion efficiency that were less than 95.0 percent; the resulting determination of whether continuous NHV monitoring is required or not in accordance with § 60.5417b(d)(8)(iii)(D), (E), or (H); and if the enclosed combustion device or flare received inert gases or other vent streams which may lower the NHV of the combined stream, whether the sampling included periods where the highest percentage of inert gases or other gases which may lower the NHV of the combined stream were sent to the enclosed combustion device or flare.

(J) If a demonstration was conducted in accordance with § 60.5417b(d)(8)(iv) that the maximum potential pressure of units manifolded to an enclosed combustion device or flare cannot cause the maximum inlet flow rate established in accordance with § 60.5417b(f)(1) or a flare tip velocity limit of 18.3 meter/second (60 feet/second) to be exceeded, an indication of whether this is a re-evaluation of the gas flow and the reason for the re-evaluation; the demonstration conducted; and applicable engineering calculations.

(K) For each periodic sampling event conducted under § 60.5417b(d)(8)(iii)(G), provide the date of the sampling, the required minimum vent gas NHV, and the NHV value for each vent gas sample.

(L) For each flare and enclosed combustion device, provide the date each device is observed with OGI in accordance with § 60.5415b(f)(1)(x) and whether uncombusted emissions were present. Provide the date each device was visibly observed during an AVO inspection in accordance with § 60.5415b(f)(1)(x), whether the pilot or combustion flame was lit at the time of observation, and whether the device was found to be operating properly.

(M) An identification of the alternative test method used.

(N) For each instance where there is a deviation of the control device in accordance with § 60.5417b(i)(6)(i) or (iii) through (v) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (*e.g.,* NHV_{cz} operating limit, lack of pilot or combustion flame, visible emissions), and cause of the deviation.

(O) For each instance where there is a deviation of the data availability in accordance with § 60.5417b(i)(6)(ii) include the date of each operating day when monitoring data are not available for at least 75 percent of the operating hours.

(P) If no deviations occurred under paragraph (b)(11)(v)(N) or (O) of this section, a statement that there were no deviations for the control device during the annual report period.

(Q) Any additional information required to be reported as specified by the Administrator as part of the alternative test method approval under § 60.5412b(d).

(12) Within 60 days after the date of completing each performance test (see § 60.8) required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413b(d), you must submit the results of the performance test following the procedures specified in paragraph (d) of this section. Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

(13) For combustion control devices tested by the manufacturer in accordance with § 60.5413b(d), an electronic copy of the performance test results required by § 60.5413b(d) shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.*

(14) If you had a super-emitter event during the reporting period, the start date of the super-emitter event, the duration of the super-emitter event in hours, and the affected facility associated with the super-emitter event, if applicable.

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

(c) * * *

(3) For each associated gas well, you must maintain the applicable records specified in paragraphs (c)(3)(i) or (ii) and (iii), (iv), (v) and (vi) of this section, as applicable.

(i) For each associated gas well that complies with the requirements of § 60.5377b(a)(1), (2), (3), or (4), you must keep the records specified in paragraphs (c)(3)(i)(A) and (B).

(A) Documentation of the specific method(s) in § 60.5377b(a)(1), (2), (3), or (4) that is used.

(B) For instances where you temporarily route the associated gas to a flare or control device in accordance with § 60.5377b(d), you must keep the records specified in paragraphs (c)(3)(i)(B)(*1*) through (*3*).

(*1*) The reason in § 60.5377b(d)(1), (2), (3), or (4) for each incident.

(2) The date of each incident, along with the times when routing the associated gas to the flare or control device started and ended, along with the total duration of each incident.

(3) Documentation that all CVS requirements specified in § 60.5411b(a) and (c) and all applicable flare or control device requirements specified in § 60.5412b are met during each period when the associated gas is routed to the flare or control device.

(ii) For instances where you temporarily vent the associated gas in accordance with § 60.5377b(e), you must keep the records specified in paragraphs (c)(3)(ii)(A) through (D) of this section. These records are required if you are routinely complying with § 60.5377b(a) or § 60.5377b(f) or temporarily complying with § 60.5377b(d).

(A) The reason in § 60.5377b(e)(1), (2), or (3) for each incident.

(B) The date of each incident, along with the times when venting the associated gas started and ended, along with the total duration of each incident.

(C) The VOC and methane emissions that were emitted during each incident.

(D) The cumulative duration of venting incidents and VOC and methane emissions for all incidents in each calendar year.

(iii) For each associated gas well that complies with the requirements of § 60.5377b(f) because it has demonstrated that it is not feasible to comply with § 60.5377b(a)(1) through (4) due to technical reasons in accordance with § 60.5377b(g), records of each annual demonstration and certification of the technical reason that it is not feasible to comply with § 60.5377b(a)(1) through (4) in accordance with § 60.5377b(g).

(iv) For each associated gas well that complies with the requirements of § 60.5377b(f), meet the recordkeeping requirements specified in paragraphs (c)(3)(iv)(A) through (E) of this section.

(A) Identification of each instance when associated gas was vented and not routed to a control device that reduces VOC and methane emissions by at least 95.0 percent.

(B) If you comply with the emission reduction standard in § 60.5377b with a control device, the information for each control device in paragraphs (c)(11) and (13) of this section.

(C) Records of the closed vent system inspection as specified in paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must maintain records of the information specified in § 60.5424b.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(v) For each instance where you route associated gas to a flare or control device beyond 72 hours due to an ''exigent circumstance'' according to § 60.5377b(d)(1) or (2), you must maintain the records specified in paragraphs (c)(3)(v)(A) through (D) of this section.

(A) A written description of the ''exigent circumstance'' requiring the need to flare or route to a control device beyond 72 hours.

(B) A description of the steps taken to resolve the need for temporary flaring/routing to a control device;

(C) The dates and times an identified ''exigent circumstance'' started and ended (*e.g.,* when owners or operators are able to access site, when personnel and/or equipment are available) and the total duration of each ''exigent circumstance''; and

(D) The dates and times temporary flaring/routing to a control device started and ended and the total duration of temporary flaring/routing to a control device due to the identified ''exigent circumstance.''

(vi) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(4) For each centrifugal compressor affected facility, you must maintain the records specified in paragraphs (c)(4)(i) through (iii) of this section.

(i) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380b, including a description of each deviation, the date and time each deviation began and the duration of each deviation.

(ii) For each wet seal compressor complying with the emissions reduction standard in § 60.5380b(a)(1), you must maintain the records in paragraphs (c)(4)(ii)(A) through (E) of this section. For each wet seal compressor complying with the alternative standard in § 60.5380b(a)(3) by routing the closed vent system to a process, you must maintain the records in paragraphs (c)(4)(ii)(B) through (E) of this section.

(A) If you comply with the emission reduction standard in § 60.5380b(a)(1) with a control device, the information for each control device in paragraph (c)(11) of this section.

(B) Records of the closed vent system inspection as specified in paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must maintain the information specified in § 60.5424b.

(C) Records of the cover inspections as specified in paragraph (c)(9) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (c)(9) of this section, you must maintain the information specified in § 60.5424b.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(iii) For each centrifugal compressor affected facility using a self-contained wet seal compressor, centrifugal compressor equipped with sour seal oil separator and capture system, or dry seal compressor complying with the standard in § 60.5380b(a)(4), (5) or (6), you must maintain the records specified in paragraphs (c)(4)(iii)(A) through (H) of this section.

(A) Records of the cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous volumetric flow rate measurement, as applicable.

(B) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(C) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(4)(iii)(C)(*1*) through (*6*).

(*1*) Description of standard method published by a consensus-based standards organization or industry standard practice.

(*2*) Records of volumetric flow rate emissions calculations conducted according to paragraphs § 60.5380b(a)(4) through (6), as applicable.

(*3*) Records of manufacturer's operating procedures and measurement methods.

(*4*) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration, and accuracy checks.

(*5*) Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

(*6*) Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

(D) Date when performance-based volumetric flow rate is exceeded.

(E) The date of successful repair of the compressor seal, including follow-up performance-based volumetric flow rate measurement to confirm successful repair.

(F) Identification of each compressor seal placed on delay of repair and explanation for each delay of repair.

(G) For each compressor seal or part needed for repair placed on delay of repair because of replacement seal or part unavailability, the operator must document: the date the seal or part was added to the delay of repair list, the date the replacement seal or part was ordered, the anticipated seal or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the seal or part.

(H) Date of planned shutdowns that occur while there are any seals or parts that have been placed on delay of repair.

(5) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(5)(i) through (x) and (c)(8) through (13) of this section, as applicable. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(i) For each reciprocating compressor affected facility, you must maintain records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385b, including a description of each deviation, the date and time each deviation began and the duration of each deviation in hours.

(ii) Records of the date of installation of a rod packing emissions collection system and closed vent system as specified in § 60.5385b(d).

(iii) Records of the cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous volumetric flow rate measurement, as applicable. Alternatively, a record that emissions from the rod packing are being routed to a process through a closed vent system.

(iv) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(v) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(5)(v)(A) through (F).

(A) Description of standard method published by a consensus-based standards organization or industry standard practice.

(B) Records of volumetric flow rate calculations conducted according to § 60.5385b(b) or (c), as applicable.

(C) Records of manufacturer operating procedures and measurement methods.

(D) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration, and accuracy checks.

(E) Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

(F) Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

(vi) Date when performance-based volumetric flow rate is exceeded.

(vii) The date of successful replacement or repair of reciprocating compressor rod packing, including follow-up performance-based volumetric flow rate measurement to confirm successful repair.

(viii) Identification of each reciprocating compressor placed on delay of repair because of rod packing or part unavailability and explanation for each delay of repair.

(ix) For each reciprocating compressor that is placed on delay of repair because of replacement rod packing or part unavailability, the operator must document: the date the rod packing or part was added to the delay of repair list, the date the replacement rod packing or part was ordered, the anticipated rod packing or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the rod packing or part.

(x) Date of planned shutdowns that occur while there are any reciprocating compressors that have been placed on delay of repair due to the unavailability of rod packing or parts to conduct repairs.

(6) For each process controller affected facility, you must maintain the records specified in paragraphs (c)(6)(i) through (vii) of this section.

(i) Records identifying each process controller that is driven by natural gas and that does not function as an emergency shutdown device.

(ii) For each process controller affected facility complying with § 60.5390b(a), you must maintain records of the information specified in paragraphs (c)(6)(ii)(A) and (B) of this section, as applicable.

(A) If you are complying with § 60.5390b(a) by routing process controller vapors to a process through a closed vent system, you must report the information specified in paragraphs (c)(6)(ii)(A)(*1*) and (*2*) of this section.

(*1*) An identification of all the natural gas-driven process controllers in the process controller affected facility for which you collect and route vapors to a process through a closed vent system.

(*2*) The records specified in paragraphs (c)(8), (10), and (12) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(B) If you are complying with § 60.5390b(a) by using a self-contained natural gas-driven process controller, you must report the information specified in paragraphs (c)(6)(ii)(B)(*1*) through (*3*) of this section.

(*1*) An identification of each process controller complying with § 60.5390b(a) by using a self-contained natural gas-driven process controller;

(*2*) Dates of each inspection required under § 60.5416b(b); and

(*3*) Each defect or leak identified during each natural gas-driven-self-contained process controller system inspection, and date of repair or date of anticipated repair if repair is delayed.

(iii) For each process controller affected facility complying with the § 60.5390b(b)(1) process controller bleed rate requirements, you must maintain records of the information specified in paragraphs (c)(6)(iii)(A) and (B) of this section.

(A) The identification of process controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh and records of the manufacturer's specifications indicating that the process controller is designed with a natural gas bleed rate of less than or equal to 6 scfh.

(B) Where necessary to meet a functional need, the identification of the process controller and demonstration of why it is necessary to use a process controller with a natural gas bleed rate greater than 6 scfh.

(iv) For each intermittent vent process controller in the affected facility complying with the requirements in paragraphs § 60.5390b(b)(2), you must keep records of the information specified in paragraphs (c)(6)(iv)(A) through (C) of this section.

(A) The identification of each intermittent vent process controller.

(B) Dates and results of the intermittent vent process controller monitoring required by § 60.5390b(b)(2)(ii).

(C) For each instance in which monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, the date of repair or replacement, or the date of anticipated repair or replacement if the repair or replacement is delayed and the date and results of the re-survey after repair or replacement.

(v) For each process controller affected facility complying with § 60.5390b(b)(3), you must maintain the records specified in paragraphs (c)(6)(v)(A) and (B) of this section.

(A) An identification of each process controller for which emissions are routed to a control device.

(B) Records specified in paragraphs (c)(8) and (10) through (13) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(vi) Records of each change in compliance method, including identification of each natural gas-driven process controller which changes its method of compliance, the new method of compliance, and the date of the change in compliance method.

(vii) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

* * * * *

(11) Records for each control device used to comply with the emission reduction standard in § 60.5377b(d) or (f) for associated gas wells, § 60.5380b(a)(1) or (9) for centrifugal compressor affected facilities, § 60.5385b(d)(2) for reciprocating compressor affected facilities, § 60.5390b(b)(3) for your process controller affected facility in Alaska, § 60.5393b(b)(3) for your pump affected facility, § 60.5395b(a)(2) for your storage vessel affected facility, § 60.5376b(g) for well affected facility gas well liquids unloading, or § 60.5400b(f) or 60.5401b(e) for your process equipment affected facility, as required in paragraphs (c)(11)(i) through (viii) of this section. If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), keep records of the information in paragraph (c)(11)(ix) of this section, in lieu of the records required by paragraphs (c)(11)(i) through (iv) and (vi) through (viii) of this section.

(i) For a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e), keep records of the information in paragraphs (c)(11)(i)(A) through (E) of this section, in addition to the records in paragraphs (c)(11)(ii) through (ix) of this section, as applicable.

(A) Serial number of purchased device and copy of purchase order.

(B) Location of the affected facility associated with the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(C) Minimum and maximum inlet gas flow rate specified by the manufacturer.

(D) Records of the maintenance and repair log as specified in § 60.5413b(e)(4), for all inspection, repair, and maintenance activities for each control device failing the visible emissions test.

(E) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(ii) For all control devices, keep records of the information in paragraphs (c)(11)(ii)(A) through (G) of this section, as applicable.

(A) Make, model, and date of installation of the control device, and identification of the affected facility controlled by the device.

(B) Records of deviations in accordance with § 60.5417b(g)(1) through (7), including a description of the deviation, the date and time the deviation began, the duration of the deviation, and the cause of the deviation.

(C) The monitoring plan required by § 60.5417b(c)(2).

(D) Make and model number of each continuous parameter monitoring system.

(E) Records of minimum and maximum operating parameter values, continuous parameter monitoring system data (including records that the pilot or combustion flame is present at all times), calculated averages of continuous parameter monitoring system data, and results of all compliance calculations.

(F) Records of continuous parameter monitoring system equipment performance checks, system accuracy audits, performance evaluations, or other audit procedures and results of all inspections specified in the monitoring plan in accordance with § 60.5417b(c)(2). Records of calibration gas cylinders, if applicable.

(G) Periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities Records of repairs on the monitoring system.

(iii) For each carbon adsorption system, records of the schedule for carbon replacement as determined by the design analysis requirements of § 60.5413b(c)(2) and (3) and records of each carbon replacement as specified in §§ 60.5412b(c)(1) and 60.5415b(f)(1)(viii).

(iv) For enclosed combustion devices and flares, records of visible emissions observations as specified in paragraph (c)(11)(iv)(A) or (B) of this section.

(A) Records of observations with Method 22 of appendix A–7 to this part, including observations required following return to operation from a maintenance or repair activity, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22–1 in Method 22 of appendix A–7 to this part.

(B) If you monitor visible emissions with a video surveillance camera, location of the camera and distance to emission source, records of the video surveillance output, and documentation that an operator looked at the feed daily, including the date and start time of observation, the length of observation, and length of time visible emissions were present.

(v) For enclosed combustion devices and flares, video of the OGI inspection conducted in accordance with § 60.5415b(f)(1)(x). Records documenting each enclosed combustion device and flare was visibly observed during each inspection conducted under § 60.5397b using AVO in accordance with § 60.5415b(f)(1)(x).

(vi) For enclosed combustion devices and flares, an indication of whether the enclosed combustion device or flare receives inert gases or other vent streams which may lower the NHV of the combined stream, and if so, a description of the operating scenario(s) which may lower the NHV of the combined stream through the introduction of inert gases or other vent gas streams. Records of each demonstration of the NHV of the inlet gas to the enclosed combustion device or flare conducted in accordance with § 60.5417b(d)(8)(iii), including the sampling approach used (continuous NHV, twice daily sampling, alternative method), the date, time and results of each analysis, and, if shorter sampling times were used with twice daily sampling, the collection time(s) used and the reason for not obtaining a full one hour sample. For each re-evaluation of the NHV of the inlet gas, records of process changes and explanation of the conditions that led to the need to re-evaluation the NHV of the inlet gas. For each demonstration where the enclosed combustion device or flare received inert gases, record the highest percentage of inert gases that can be sent to the enclosed combustion device or flare and the highest percent of inert gases sent to the enclosed combustion device or flare during the NHV demonstration. Records of periodic sampling conducted under § 60.5417b(d)(8)(iii)(G).

(vii) For enclosed combustion devices and flares, if you use a backpressure regulator valve, the make and model of the valve, date of installation, and record of inlet flow rating. Maintain records of the engineering evaluation and manufacturer specifications that identify the pressure set point corresponding to the minimum inlet gas flow rate, the annual confirmation that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications, and the annual confirmation that the backpressure regulator valve fully closes when not in open position.

(viii) For enclosed combustion devices and flares, records of each demonstration required under § 60.5417b(d)(8)(iv).

(ix) If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), keep records of the information in paragraphs (c)(11)(ix)(A) through (H) of this section, in lieu of the records required by paragraphs (c)(11)(i) through (iv) and (vi) through (viii) of this section.

(A) An identification of the alternative test method used.

(B) Data recorded at the intervals required by the alternative test method.

(C) Monitoring plan required by § 60.5417(i)(2).

(D) Quality assurance and quality control activities conducted in accordance with the alternative test method.

(E) If required by § 60.5412b(d)(4) to conduct visible emissions observations, records required by paragraph (c)(11)(iv) of this section.

(F) If required by § 60.5412b(d)(5) to conduct pilot or combustion flame monitoring, record indicating the presence of a pilot or combustion flame and periods when the pilot or combustion flame is absent.

(G) For each instance where there is a deviation of the control device in accordance with § 60.5417b(i)(6)(i) through (v), the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation.

(H) Any additional information required to be recorded as specified by the Administrator as part of the alternative test method approval under § 60.5412b(d).

(12) For each closed vent system routing to a control device or process, the records of the assessment conducted according to § 60.5411b(c):

(i) A copy of the assessment conducted according to § 60.5411b(c)(1); and

(ii) A copy of the certification according to § 60.5411b(c)(1)(i) and (ii).

(13) A copy of each performance test submitted under paragraph (b)(12) or (13) of this section.

(14) For the fugitive emissions components affected facility, maintain the records identified in paragraphs (c)(14)(i) through (viii) of this section.

(i) The date of the startup of production or the date of the first day of production after modification for the fugitive emissions components affected facility at a well site and the date of startup or the date of modification for the fugitive emissions components affected facility at a compressor station.

(ii) For the fugitive emissions components affected facility at a well site, you must maintain records specifying what type of well site it is (*i.e.,* single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment.)

(iii) For the fugitive emissions components affected facility at a well site where you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, record the date the well site completes the removal of all major production and processing equipment from the well site, and, if the well site is still producing, record the well ID or separate tank battery ID receiving the production from the well site. If major production and processing equipment is subsequently added back to the well site, record the date that the first piece of major production and processing equipment is added back to the well site.

(iv) The fugitive emissions monitoring plan as required in § 60.5397b(b), (c), and (d).

(v) The records of each monitoring survey as specified in paragraphs (c)(14)(v)(A) through (I) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s), training, and experience of the operator(s) performing the survey.

(D) Monitoring instrument or method used.

(E) Fugitive emissions component identification when Method 21 of appendix A–7 to this part is used to perform the monitoring survey.

(F) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey. For compressor stations, operating mode of each compressor (*i.e.,* operating, standby pressurized, and not operating-depressurized modes) at the station at the time of the survey.

(G) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(H) Records of calibrations for the instrument used during the monitoring survey.

(I) Documentation of each fugitive emission detected during the monitoring survey, including the information specified in paragraphs (c)(14)(v)(I)(*1*) through (*9*) of this section.

(*1*) Location of each fugitive emission identified.

(*2*) Type of fugitive emissions component, including designation as difficult-to-monitor or unsafe-to-monitor, if applicable.

(*3*) If Method 21 of appendix A–7 to this part is used for detection, record the component ID and instrument reading.

(*4*) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph or video must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture). The digital photograph or identification (*e.g.,* tag) may be removed after the repair is completed, including verification of repair with the resurvey.

(*5*) The date of first attempt at repair of the fugitive emissions component(s).

(*6*) The date of successful repair of the fugitive emissions component, including the resurvey to verify repair and instrument used for the resurvey.

(*7*) Identification of each fugitive emission component placed on delay of repair and explanation for each delay of repair.

(*8*) For each fugitive emission component placed on delay of repair for reason of replacement component unavailability, the operator must document: the date the component was added to the delay of repair list, the date the replacement fugitive component or part thereof was ordered, the anticipated component delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the component.

(*9*) Date of planned shutdowns that occur while there are any components that have been placed on delay of repair.

(vi) For the fugitive emissions components affected facility complying with an alternative means of emissions limitation under § 60.5399b, you must maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(vii) For well closure activities, you must maintain the information specified in paragraphs (c)(14)(vii)(A) through (G) of this section.

(A) The well closure plan developed in accordance with § 60.5397b(l) and the date the plan was submitted.

(B) The notification of the intent to close the well site and the date the notification was submitted.

(C) The date of the cessation of production from all wells at the well site.

(D) The date you began well closure activities at the well site.

(E) Each status report for the well closure activities reported in paragraph (b)(9)(iv)(A) of this section.

(F) Each OGI survey reported in paragraph (b)(9)(iv)(B) of this section including the date, the monitoring instrument used, and the results of the survey or resurvey.

(G) The final OGI survey video demonstrating the closure of all wells at the site. The video must include the date that the video was taken and must identify the well site location by latitude and longitude.

(viii) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (c)(14)(iv) and (v) of this section, you must maintain the records specified in § 60.5424b.

(15) For each pump affected facility, you must maintain the records identified in paragraphs (c)(15)(i) through (ix) of this section.

(i) Identification of each pump that is driven by natural gas and that is in operation 90 days or more per calendar year.

(ii) If you are complying with § 60.5393b(a) or (b)(1) by routing pump vapors to a process through a closed vent system, identification of all the pumps in the pump affected facility for which you collect and route vapors to a process through a closed vent system and the records specified in paragraphs (c)(8), (10), and (12) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(iii) If you are complying with § 60.5393b(b)(1) by routing pump vapors to control device achieving a 95.0 percent reduction in methane and VOC emissions, you must keep the records specified in paragraphs (c)(8) and (10) through (13) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(iv) If you are complying with § 60.5393b(b)(5) by routing pump vapors to control device achieving less than a 95.0 percent reduction in methane and VOC emissions, you must maintain records of the certification that there is a control device on site but it does not achieve a 95.0 percent emissions reduction and a record of the design evaluation or manufacturer's specifications which indicate the percentage reduction the control device is designed to achieve.

(v) If you have less than three natural gas-driven diaphragm pumps in the pump affected facility, and you do not have a vapor recovery unit or control device installed on site by the compliance date, you must retain a record of your certification required under § 60.5393b(b)(6), certifying that there is no vapor recovery unit or control device on site. If you subsequently install a control device or vapor recovery unit, you must maintain the records required under paragraph (c)(15)(ii), (iii) or (iv) of this section, as applicable.

(vi) If you determine, through an engineering assessment, that it is technically infeasible to route the pump affected facility emissions to a process or control device, you must retain records of your demonstration and certification that it is technically infeasible as required under § 60.5393b(b)(5).

(vii) If the pump is routed to a control device that is subsequently removed from the location or is no longer available such that there is no option to route to a control device, you are required to retain records of this change and the records required under paragraph (c)(15)(vi) of this section.

(viii) Records of each change in compliance method, including identification of each natural gas-driven pump which changes its method of compliance, the new method of compliance, and the date of the change in compliance method.

(ix) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(d) *Electronic reporting.* If you are required to submit notifications or reports following the procedure specified in this paragraph (d), 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 (d)(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 (d).

(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 *oaqpscbi@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 Oil and Natural Gas 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 *oaqpscbi@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. ERT files should be sent to the secondary attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the secondary attention of the Oil and Natural Gas Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

* * * * *

Subpart OOOOc—Emissions Guidelines for Greenhouse Gas Emissions From Existing Crude Oil and Natural Gas Facilities

■ 6. Amend § 60.5391c by revising paragraphs (b) through (e) to read as follows:

§ 60.5391c What GHG standards apply to associated gas wells at well designated facilities?

* * * * *

(b) If you meet one of the conditions in paragraph (b)(1) or (2) of this section, you may route the associated gas to a control device that reduces methane emissions by at least 95.0 percent instead of complying with paragraph (a) of this section. The associated gas must be routed through a closed vent system that meets the requirements of § 60.5411c(a) and (c) and the control device must meet the conditions specified in § 60.5412c(a) through (c).

(1) If the annual methane contained in the associated gas from your oil well is 40 tons per year or less at the initial compliance date, determined in accordance with paragraph (e) of this section.

(2) If you demonstrate and certify that it is not feasible to comply with paragraphs (a)(1) through (4) of this section due to technical reasons by providing a detailed analysis documenting and certifying the technical reasons for this infeasibility in accordance with paragraphs (b)(2)(i) through (iv) of this section.

(i) In order to demonstrate that it is not feasible to comply with paragraphs (a)(1) through (4) of this section, you must provide a detailed analysis documenting and certifying the technical reasons for this infeasibility. The demonstration must address the technical infeasibility for all options identified in paragraphs (a)(1) through (4). Documentation of these demonstrations must be maintained in accordance with § 60.5420c(c)(2)(iv).

(ii) This demonstration must be certified by a professional engineer or another qualified individual with expertise in the uses of associated gas. The following certification, signed and dated by the qualified professional engineer or other qualified individual shall state: ''I certify that the assessment of technical and safety infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared pursuant to the requirements of § 60.5391c(b)(2). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.''

(iii) This demonstration and certification are valid for no more than 12 months. You must re-analyze the feasibility of complying with paragraphs (a)(1) through (4) of this section and finalize a new demonstration and certification each year.

(iv) Documentation of these demonstrations, along with the certifications, must be maintained in accordance with § 60.5420c(c)(2)(iv) and submitted in annual reports in accordance with § 60.5420c(b)(3).

(c) If you are complying with paragraph (a) of this section, you may temporarily route the associated gas to a flare or control device in the situations and for the durations identified in paragraph (c)(1), (2), (3), or (4) of this section. The associated gas must be routed through a closed vent system that meets the requirements of § 60.5411c(a) and (c) and the control device must meet the conditions specified in § 60.5412c. If you are routing to a flare, you must demonstrate that the § 60.18 flare requirements are met during the period when the associated gas is routed to the flare. Records must be kept of all temporary flaring instances in accordance with § 60.5420c(c)(2) and reported in the annual report in accordance with § 60.5420c(b)(3).

(1) During a malfunction or incident that endangers the safety of operator personnel or the public you are allowed to route associated gas to a flare or control device until the malfunction or incident is resolved but not longer than 72 hours per incident. Temporarily routing associated gas to a flare or control device is allowed only until the malfunction or incident is resolved. Notwithstanding the previous sentences, if there are exigent circumstances that reasonably require routing to a flare or control device for more than 72 hours, paragraphs (c)(1)(i) through (iii) of this section apply.

(i) An ''exigent circumstance'' for purposes of this paragraph (c)(1) is a situation that results in the inability to reasonably access a site with the necessary equipment and personnel to address and resolve incidents that cause the need to temporarily flare associated gas for more than 72 hours. This includes circumstances where there is a need to flare beyond 72 hours due to an unexpected malfunction event and equipment needed to resolve an incident are not readily available due to an owner's or operator's inability to secure the required equipment for reasons beyond an owner's or operator's control (*i.e.,* supply chain issues); or there is a temporary shortage of personnel needed to resolve an incident due to a circumstance such as a declared national pandemic that is beyond an owner's or operator's control.

(ii) Temporarily routing associated gas to a flare or control device is allowed until the malfunction or incident is resolved, but shall not be longer than 72 hours after the site can be accessed following the passing of the exigent circumstance.

(iii) For instances where you route associated gas to a flare or control device for more than 72 hours, you must meet the reporting requirements specified in § 60.5420c(b)(3)(i)(B)(*4*) and must maintain the records specified in § 60.5420c(c)(2)(vi).

(2) During repair and maintenance, including blow downs, a production test, or commissioning, you are allowed to route associated gas to a flare or control device until the incident is resolved, but not longer than 72 hours per incident. Temporarily routing associated gas to a flare or control device is allowed only until the incident is resolved. Notwithstanding the previous sentences, if there are exigent circumstances that reasonably require routing to a flare or control device for more than 72 hours, paragraphs (c)(1)(i) through (iii) apply.

(3) For wells complying with paragraph (a)(1) of this section, for the duration of a temporary interruption in service from the gathering or pipeline system, or 30 days, whichever is less.

(4) For 72 hours from the time that the associated gas does not meet pipeline specifications, or until the associated

gas meets pipeline specifications, whichever is less.

(d) If you are complying with paragraph (a), (b), or (c) of this section, you may vent the associated gas in the situations and for the durations identified in paragraph (d)(1), (2), or (3) of this section. Records must be kept of all venting instances in accordance with § 60.5420c(c)(2) and reported in the annual report in accordance with § 60.5420c(b)(3).

(1) For up to 12 hours to protect the safety of personnel.

(2) For up to 30 minutes during bradenhead monitoring.

(3) For up to 30 minutes during a packer leakage test.

(e) Calculate the methane content in associated gas as specified in paragraph (e)(1) of this section and comply with paragraphs (e)(2) and (3) of this section.

(1) Calculate the methane content in associated gas from your oil well using the following equation:

Equation 1 to Paragraph (e)(1)

$$AG_{methane} = \frac{(GOR \times V \times M_{methane} \times 0.0192)}{907.2}$$

Where:

$AG_{methane}$ = Amount of methane in associated gas from the oil well, tons methane per year.

GOR = Gas to oil ratio for the well in standard cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities. GOR is to be determined for the well using available data, an appropriate standard method published by a consensus-based standards organization which include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB), or in industry standard practice.

V = Volume of oil produced in the calendar year preceding the initial compliance date, in barrels per year.

$M_{methane}$ = mole fraction of methane in the associated gas.0.0192 = density of methane gas at 60 °F and 14.7 psia in kilograms per cubic foot.

907.2 = conversion of kilograms to tons, kilograms per ton.

(2) You must maintain records of the calculation of the methane in associated gas from your oil well results in accordance with § 60.5420c(c)(2), and submit the information, as well as the background information, in the next annual report in accordance with § 60.5420c(b)(3).

(3) If a process change occurs that could increase the methane content in the associated gas, you must recalculate the methane content in accordance with paragraph (e)(1) of this section.

* * * * *

■ 7. Amend § 60.5412c by revising paragraphs (a)(1)(iv), (a)(3), and (d)(1) to read as follows:

§ 60.5412c What additional requirements must I meet for determining initial compliance of my control devices?

* * * * *

(a) * * *

(1) * * *

(iv) For an enclosed combustion device other than those meeting the operating limits in paragraphs (a)(1)(ii), (iii), and (v) of this section, you must maintain the net heating value (NHV) of the gas sent to the enclosed combustion device at or above the applicable limits specified in paragraphs (a)(1)(iv)(A) through (C) of this section.

(A) For enclosed combustion devices that do not use assist gas or pressure-assisted burner tips to promote mixing at the burner tip, 200 British thermal units (Btu) per standard cubic foot (Btu/scf).

(B) For enclosed combustion devices that use pressure-assisted burner tips to promote mixing at the burner tip, 800 Btu/scf.

(C) For steam-assisted and air-assisted enclosed combustion devices, 300 Btu/scf.

* * * * *

(3) Each flare must be designed and operated according to the requirements specified in paragraphs (a)(3)(i) through (vii) of this section, as applicable. Alternatively, flares must meet the requirements specified in paragraph (d) of this section.

(i) For unassisted flares, you must maintain the NHV of the vent gas sent to the flare at or above 200 Btu/scf.

(ii) For flares that use pressure-assisted burner tips to promote mixing at the burner tip, you must maintain the NHV of the vent gas sent to the flare at or above 800 Btu/scf.

(iii) For steam-assisted and air-assisted flares, you must maintain the NHV of the vent gas sent to the flare at or above 300 Btu/scf.

(iv) For flares other than pressure-assisted flares, you must determine the maximum flow rate of vent gas to the control system based on the design considerations of the designated facilities to demonstrate compliance with the flare tip velocity limits in § 60.18(b) according to § 60.5417c(d)(8)(iv). The maximum flare tip velocity limits do not apply for pressure-assisted flares.

(v) You must operate the flare at or above the minimum inlet gas flow rate. The minimum inlet gas flow rate is established based on manufacturer recommendations.

(vi) You must operate the flare with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. You must conduct the compliance determination with the visible emission limits using Method 22 of appendix A–7 to this part, or you must monitor the flare according to § 60.5417c(h).

(vii) You must install and operate a continuous burning pilot or combustion flame. An alert must be sent to the nearest control room whenever the pilot flame is unlit.

* * * * *

(d) * * *

(1) The alternative method must be capable of demonstrating continuous compliance with a combustion efficiency of 95.0 percent or greater.

* * * * *

■ 8. Amend § 60.5415c by revising paragraphs (c), (e)(1)(vii), (e)(1)(xi)(A), (f), (h), and (i)(15) to read as follows:

§ 60.5415c How do I demonstrate continuous compliance with the standards for each of my designated facilities?

* * * * *

(c) *Centrifugal compressor designated facility.* For each centrifugal compressor designated facility complying with the volumetric flow rate measurements requirements in § 60.5392c(a)(1) and (2), you must demonstrate continuous compliance according to paragraphs (c)(1), (3), and (4) of this section. Alternatively, for each centrifugal compressor designated facility complying with § 60.5392c(a)(3) and either § 60.5392c(a)(4) or (5) by routing emissions to a control device or to a process, you must demonstrate continuous compliance according to paragraphs (c)(2) through (4) of this section.

(1) You must maintain volumetric flow rate at or below the volumetric flow rates specified in paragraphs (c)(1)(i) through (iii) of this section for your centrifugal compressor, as applicable, and you must conduct the

required volumetric flow rate measurement of your dry or wet seal in accordance with § 60.5392c(a)(1) and (2) on or before 8,760 hours of operation after your last volumetric flow rate measurement which demonstrates compliance with the applicable volumetric flow rate.

(i) For your wet seal centrifugal compressors (including self-contained wet seal centrifugal compressors), you must maintain the volumetric flow rate at or below 3 scfm per seal (or in the case of manifolded groups of seals, 3 scfm multiplied by the number of seals).

(ii) For your Alaska North Slope centrifugal compressor equipped with sour seal oil separator and capture system, you must maintain the volumetric flow rate at or below 9 scfm per seal (or in the case of manifolded groups of wet seals, 9 scfm multiplied by the number of seals).

(iii) For your dry seal compressor, you must maintain the volumetric flow rate at or below 10 scfm per seal (or in the case of manifolded groups of wet seals, 10 scfm multiplied by the number of seals).

(2) For each wet seal and dry seal centrifugal compressor designated facility complying by routing emissions to a control device or to a process, you must operate the wet seal emissions collection system and dry seal system to route emissions to a control device or a process through a closed vent system and continuously comply with the closed vent requirements of § 60.5416c. If you comply with § 60.5392c(a)(4) by using a control device, you also must comply with the requirements in paragraph (e) of this section.

(3) You must submit the annual reports as required in § 60.5420c(b)(1), (4) and (10)(i) through (iv), as applicable.

(4) You must maintain records as required in § 60.5420c(c)(3) and (7) through (9) and (11), as applicable.

* * * * *

(e) * * *

(1) * * *

(vii) If you use an enclosed combustion device to meet the requirements of § 60.5412c(a)(1) and you demonstrate compliance using the test procedures specified in § 60.5413c(b), or you use a flare designed and operated in accordance with § 60.5412c(a)(3), you must comply with the applicable requirements in paragraphs (e)(1)(vii)(A) through (E) of this section.

(A) For each enclosed combustion device which is not a catalytic vapor incinerator and for each flare, you must comply with the requirements in paragraphs (e)(1)(vii)(A)(*1*) through (*4*) of this section.

(1) A pilot or combustion flame must be present at all times of operation. An alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

(*2*) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22 of appendix A–7 to this part, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes or once the amount of time visible emissions is present has exceeded 1 minute, whichever time period is less. Alternatively, you may conduct visible emissions monitoring according to § 60.5417c(h).

(*3*) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(*4*) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A–7 to this part visual observation as described in paragraph (e)(1)(vii)(D) of this section or be monitored according to § 60.5417c(h).

(B) For flares, you must comply with the requirements in paragraphs (e)(1)(vii)(B)(*1*) through (*5*) of this section.

(*1*) For unassisted flares, maintain the NHV of the gas sent to the flare at or above 200 Btu/scf.

(*2*) If you use a pressure assisted flare, maintain the NHV of gas sent to the flare at or above 800 Btu/scf.

(*3*) For steam-assisted and air-assisted flares, maintain the NHV of gas sent to the flare at or above 300 Btu/scf.

(*4*) Unless you use a pressure-assisted flare, maintain the flare tip velocity below the applicable limits in § 60.18(b).

(5) Maintain the total gas flow to the flare above the minimum inlet gas flow rate. The minimum inlet gas flow rate is established based on manufacturer recommendations.

(C) For enclosed combustion devices for which, during the performance test conducted under § 60.5413c(b), the combustion zone temperature is not an indicator of destruction efficiency, you must comply with the requirements in paragraphs (e)(1)(vii)(C)(*1*) through (*4*) of this section, as applicable.

(*1*) Maintain the total gas flow to the enclosed combustion device at or above the minimum inlet gas flow rate and at or below the maximum inlet flow rate for the enclosed combustion device established in accordance with § 60.5417c(f).

(*2*) For unassisted enclosed combustion devices, maintain the NHV of the gas sent to the enclosed combustion device at or above 200 Btu/scf.

(*3*) For enclosed combustion devices that use pressure-assisted burner tips to promote mixing at the burner tip, maintain the NHV of the gas sent to the enclosed combustion device at or above 800 Btu/scf.

(*4*) For steam-assisted and air-assisted enclosed combustion devices, maintain the NHV-of gas sent to the flare at or above 300 Btu/scf.

(D) For enclosed combustion devices for which, during the performance test conducted under § 60.5413c(b), the combustion zone temperature is demonstrated to be an indicator of destruction efficiency, you must comply with the requirements in paragraphs (e)(1)(vii)(D)(*1*) and (*2*) of this section.

(*1*) Maintain the temperature at or above the minimum temperature established during the most recent performance test. The minimum temperature limit established during the most recent performance test is the average temperature recorded during each test run, averaged across the 3 test runs (average of the test run averages).

(*2*) Maintain the total gas flow to the enclosed combustion device at or above the minimum inlet gas flow rate and at or below the maximum inlet flow rate for the enclosed combustion device established in accordance with § 60.5417c(f).

(E) For catalytic vapor incinerators you must operate the catalytic vapor incinerator at or above the minimum temperature of the catalyst bed inlet and at or above the minimum temperature differential between the catalyst bed inlet and the catalyst bed outlet established in accordance with § 60.5417c(f).

* * * * *

(xi) * * *

(A) You must maintain the combustion efficiency at or above 95.0 percent.

* * * * *

(f) *Reciprocating compressor designated facility.* For each reciprocating compressor designated facility complying with § 60.5393c(a) through (c), you must demonstrate continuous compliance according to paragraphs (f)(1), (3), (5), and (6) of this section. For each reciprocating compressor designated facility complying with § 60.5393c(d)(1) or (2), you must demonstrate continuous compliance according to paragraphs (f)(2), (5), and (6) of this section. For each reciprocating compressor affected facility complying with § 60.5393c(d)(3), you must demonstrate continuous compliance according to paragraphs (f)(3) through (6) of this section.

(1) You must maintain the volumetric flow rate at or below 2 scfm per cylinder (or at or below the combined volumetric flow rate determined by multiplying the number of cylinders by 2 scfm), and you must conduct the required volumetric flow rate measurement of your reciprocating compressor rod packing vents in accordance with § 60.5393c(b) or (c) on or before 8,760 hours of operation after your last volumetric flow rate measurement which demonstrated compliance with the applicable volumetric flow rate.

(2) You must operate the rod packing emissions collection system to route emissions to a control device or to a process through a closed vent system and continuously comply with the cover and closed vent requirements of § 60.5416c. If you comply with § 60.5393c(d) by using a control device, you also must comply with the requirements in paragraph (e) of this section.

(3) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility since initial startup, since 60 days after the state plan submittal deadline (as specified in § 60.5362c(c)), since the previous flow rate measurement, or since the date of the most recent reciprocating compressor rod packing replacement, whichever date is latest.

(4) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 8,760 hours.

(5) You must submit the annual reports as required in § 60.5420c(b)(1) and (5) and (b)(10)(i) through (iv), as applicable.

(6) You must maintain records as required in § 60.5420c(c)(4), (7) through (9), and (11), as applicable.

* * * * *

(h) *Storage vessel designated facility.* For each storage vessel designated facility, you must demonstrate continuous compliance with the requirements of § 60.5396c according to paragraphs (h)(1) through (10) of this section, as applicable.

(1) For each storage vessel designated facility complying with the requirements of § 60.5396c(a)(2), you must demonstrate continuous compliance according to paragraphs (h)(5) and (9) and (10) of this section.

(2) For each storage vessel designated facility complying with the requirements of § 60.5396c(a)(3), you must demonstrate continuous compliance according to paragraph (h)(2)(i), (ii), or (iii) of this section, as applicable, and paragraphs (h)(9) and (10) of this section.

(i) You must maintain the uncontrolled actual methane emissions from the storage vessel designated facility at less than 14 tpy.

(ii) You must comply with paragraph (h)(5) of this section as soon as liquids from the well are routed to the storage vessel designated facility following fracturing or refracturing according to the requirements of § 60.5396c(a)(3)(i).

(iii) You must comply with paragraph (h)(5) of this section within 30 days of the monthly determination according to the requirements of § 60.5396c(a)(3)(ii), where the monthly emissions determination indicates that methane emissions from your storage vessel designated facility increase to 14 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel designated facility.

(3) For each storage vessel designated facility or portion of a storage vessel designated facility removed from service, you must demonstrate compliance with the requirements of § 60.5396c(c)(1) or (2) by complying with paragraphs (h)(6), (7), (9), and (10) of this section.

(4) For each storage vessel designated facility or portion of a storage vessel designated facility returned to service, you must demonstrate compliance with the requirements of § 60.5396c(c)(3) and (4) by complying with paragraphs (h)(8) through (10) of this section.

(5) For each storage vessel designated facility, you must comply with paragraphs (h)(5)(i) and (ii) of this section.

(i) You must reduce methane emissions as specified in § 60.5396c(a)(2).

(ii) For each control device installed to meet the requirements of § 60.5396c(a)(2), you must demonstrate continuous compliance with the performance requirements of § 60.5412c for each storage vessel designated facility using the procedure specified in paragraphs (h)(5)(ii)(A) and (B) of this section. When routing emissions to a process, you must demonstrate continuous compliance as specified in paragraph (h)(5)(ii)(A) of this section.

(A) You must comply with § 60.5416c for each cover and closed vent system.

(B) You must comply with the requirements specified in paragraph (e) of this section.

(6) You must completely empty and degas each storage vessel, such that each storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. For a portion of a storage vessel designated facility to be removed from service, you must completely empty and degas the storage vessel(s), such that the storage vessel(s) no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(7) You must disconnect the storage vessel(s) from the tank battery by isolating the storage vessel(s) from the tank battery such that the storage vessel(s) is no longer manifolded to the tank battery by liquid or vapor transfer.

(8) You must determine the designated facility status of a storage vessel returned to service as provided in § 60.5386c(e)(5).

(9) You must submit the annual reports as required by § 60.5420c(b)(1) and (7) and (b)(10)(i) through (iv).

(10) You must maintain the records as required by § 60.5420c(c)(6) through (9) and (11), as applicable.

(i) * * *

(15) You must maintain the records specified by § 60.5420c(c)(7), (9), and (11) as applicable and § 60.5421c.

* * * * *

■ 9. Amend § 60.5417c by revising paragraphs (d)(8), (e), (f)(1)(iv), (g)(1), (6) and (7), and (i)(6)(i) to read as follows:

§ 60.5417c What are the continuous monitoring requirements for my control devices?

* * * * *

(d) * * *

(8) For an enclosed combustion device, other than those listed in paragraphs (d)(1) through (3) and (7) of this section, or for a flare, continuous monitoring systems as specified in paragraphs (d)(8)(i) through (iv) of this section and visible emission observations conducted as specified in paragraph (d)(8)(v) of this section.

(i) Continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times. An alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.

(ii) Except as provided in this paragraph (d)(8)(ii) and paragraph (d)(8)(iii) of this section, use one of the following methods to continuously determine the NHV of the inlet gas to the enclosed combustion device or flare at standard conditions. Except for pressure assisted flares and pressure assisted enclosed combustion devices, if the inlet gas stream to the flare or enclosed combustion device does not include streams from processes or equipment where inert gas or other vent gas streams which may lower the NHV of the combined stream are added (*e.g.,* vent streams from acid gas removal (AGR) system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers without water removal, vent streams from compressors in acid gas service, vent streams containing water or CO_2 used for enhanced oil recovery, vent streams from storage vessels with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV, vent streams from gas plants that receive acid gas from sweetening units, and vent streams from nitrogen removal units (NRU)), the NHV of the inlet stream is considered to be sufficiently above the minimum required NHV for the inlet gas, and you are not required to conduct the continuous monitoring in this paragraph (d)(8)(ii) or the demonstration in paragraph (d)(8)(iii) of this section, but you must submit the report in § 60.5420c(b)(10)(v)(I) and maintain the record in § 60.5420c(c)(10)(vi) indicating that the flare or enclosed combustion device does not receive inert gas or other vent gas streams which may lower the NHV of the combined stream.

(A) A calorimeter with a minimum accuracy of ±2 percent of span.

(B) A gas chromatograph that meets the requirements in paragraphs (d)(8)(ii)(B)(*1*) through (*5*) of this section.

(*1*) You must follow the procedure in Performance Specification 9 of appendix B to this part, except that a single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C). Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to National Institute of Standards and Technology (NIST) standards.

(*2*) You must meet the accuracy requirements in Performance Specification 9 of appendix B to this part.

(*3*) You must use a calibration gas or multiple gases that includes the compounds that are reasonably expected to be present in the flare gas stream. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. You may only use the compounds used to calibrate the gas chromatograph in the calculation of the vent gas NHV.

(*4*) In lieu of the calibration gas described in paragraph (d)(8)(ii)(B)(*3*) of this section, you may use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. Use the response factor for the nearest normal hydrocarbon (*i.e.,* n-alkane) in the calibration mixture to quantify unknown components detected in the analysis. Use the response factor for n-pentane to quantify unknown components detected in the analysis that elute after n-pentane.

(*5*) To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use any published values for the net heating value per mole at 25 °C and 1 atmosphere and use 20 °C as the standard temperature for determining the volume corresponding to one mole of vent gas.

(C) A mass spectrometer that meets the requirements in paragraphs (d)(8)(ii)(C)(*1*) through (*6*) of this section.

(*1*) You must meet applicable requirements in Performance Specification 9 of appendix B of this part for continuous monitoring system acceptance including, but not limited to, performing an initial multi-point calibration check at three concentrations following the procedure in Section 10.1. A single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C). Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to NIST standards.

(*2*) The average instrument calibration error (CE) for each calibration compound at any calibration concentration must not differ by more than 10 percent from the certified cylinder gas value. The CE for each component in the calibration blend must be calculated using the following equation:

Equation 1 to Paragraph (d)(8)(ii)(C)(*2*)

$$CE = \frac{C_m - C_a}{C_a} \times 100$$

Where:

C_m = Average instrument response (ppm).
C_a = Certified cylinder gas value (ppm).

(*3*) You must use a calibration gas or multiple gases that includes the compounds that are reasonably expected to be present in the flare gas stream. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. You may only use the compounds used to calibrate the mass spectrometer in the calculation of the vent gas NHV.

(*4*) In lieu of the calibration gas described in paragraph (d)(8)(ii)(C)(*3*) of this section, you may use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. For unknown gas components that have similar analytical mass fragments to calibration compounds, you may report the unknowns as an increase in the overlapped calibration gas compound. For unknown compounds that produce mass fragments that do not overlap calibration compounds, you may use the response factor for the nearest molecular weight hydrocarbon in the calibration mix to quantify the unknown component. You may use the response factor for n-pentane to quantify any unknown components detected with a higher molecular weight than n-pentane.

(*5*) You must perform an initial calibration to identify mass fragment overlap and response factors for the target compounds.

(*6*) To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use any published value for the net heating value per mole at 25 °C and 1 atmosphere use 20 °C as the standard temperature for determining the volume corresponding to one mole of vent gas.

(D) A grab sampling system capable of collecting an evacuated canister sample for subsequent compositional analysis at least once every eight hours. Subsequent compositional analysis of the samples must be performed according to ASTM D1945–14 (R2019) or alternatively GPA 2261–19 (incorporated by reference, see § 60.17). To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use the net heating value per mole at 25 °C and 1 atmosphere use 20 °C as the standard temperature for determining the volume corresponding to one mole of vent gas.

(iii) As an alternative to the continuous composition monitoring requirements in paragraph (d)(8)(ii) of this section, a sampling demonstration may be used as specified in this paragraph. Flares or enclosed combustion devices that are not required to monitor flare gas composition because the inlet gas streams to the flare or enclosed combustion device does not include streams from processes or equipment where inert gas or other vent gas streams which may lower the NHV of the combined stream are added (*e.g.,* vent streams from acid gas removal (AGR) system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers without water removal, vent streams from compressors in acid gas service, vent streams containing water or CO_2 used for enhanced oil recovery, vent streams from storage vessels with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV, vent streams from gas plants that receive acid gas from sweetening units, and vent streams from nitrogen removal units (NRU)), are not required to conduct sampling demonstrations specified in this paragraph. For flare or enclosed combustion device, if you demonstrate according to the methods described in paragraphs (d)(8)(iii)(A) through (F) of this section that the NHV of the inlet gas to the enclosed combustion device or flare consistently exceeds the applicable operating limit specified in § 60.5415c(e)(1)(vii)(B) or (C), continuous monitoring of the NHV is not required, but you must conduct the ongoing sampling in paragraph (d)(8)(iii)(G) of this section. For an unassisted or pressure-assisted flare or enclosed combustion device, in lieu of conducting the demonstration outlined in paragraphs (d)(8)(iii)(A) through (D) of this section, you may conduct the demonstration outlined in paragraph (d)(8)(iii)(H) of this section, but you must still comply with paragraphs (d)(8)(iii)(E) through (G) of this section.

(A) Continuously monitor the inlet stream which is routed to the flare or enclosed combustor for 14 operating days or collect a sample of the inlet gas which is routed to the enclosed combustion device or flare twice daily to determine the average NHV of the gas stream for 14 operating days with no sampling day to be spaced more than 3 operating days apart from the previous sampling day. If you do not continuously monitor the NHV, the minimum time of collection for each individual sample be at least one hour when technically feasible. When it is not technically feasible to collect individual samples for at least one hour (*e.g.,* low or intermittent flow), the collection time must be as long as possible up to one hour. For samples taken during low or intermittent flow events, the collection time and the reason for not obtaining a full one hour sample must be documented and reported with the NHV sampling results. Samples must be separated by at least 6 hours. If inlet gas flow is intermittent such that there are not at least 28 samples over the 14 operating day period, you must continue to collect samples of the inlet gas beyond the 14 operating day period until you collect a minimum of 28 samples.

(B) If you collect samples twice per day, count the number of samples where the NHV value is less than 1.2 times the applicable operating limit specified in § 60.5415c(e)(1)(vii)(B) or (C) (*i.e.,* values that are less than 240, 360, or 960 Btu/scf, as applicable) during the sample collection period in paragraph (d)(8)(iii)(A) of this section.

(C) If you continuously sample the inlet stream for 14 days, count the number of hourly block average (*e.g.,* noon to 1 p.m., 1 p.m. to 2 p.m., etc.) NHV values that are less than the applicable operating limit specified in § 60.5415c(e)(1)(vii)(B) or (C), (*i.e.,* values that are less than 200, 300, or 800 Btu/scf, as applicable), during the sample collection period in paragraph (d)(8)(iii)(A) of this section.

(D) If there are no samples counted under paragraph (d)(8)(iii)(B) of this section or there are no hourly values counted under paragraph (d)(8)(iii)(C) of this section, the gas stream is considered to consistently exceed the applicable NHV operating limit and on-going continuous monitoring is not required.

(E) If process operations are revised that could reduce the NHV of the gas sent to the enclosed combustion device or flare, such as the removal or addition of process equipment, and at any time the Administrator requires, re-evaluation of the gas stream must be performed according to paragraphs (d)(8)(iii)(A) through (D) of this section within 60 days of the revisions to process operations to ensure the gas stream still consistently exceeds the applicable operating limit specified in § 60.5415c(e)(1)(vii)(B) or (C), or this paragraph (d)(8)(iii). If any of the samples counted under paragraph (d)(8)(iii)(B) of this section or any hourly values counted under paragraph (d)(8)(iii)(C) of this section are less than the limits in the respective paragraph you must conduct the continuous monitoring required by one of the options specified in paragraphs (d)(8)(ii)(A) through (D) of this section within 60 days of the re-evaluation of the gas stream.

(F) When collecting samples under paragraph (d)(8)(iii)(A) of this section, the owner or operator must account for any sources of inert gases or other vent gas streams which may lower the NHV of the combined stream (*e.g.,* vent streams from AGR system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers, vent streams from compressors in acid gas service, vent streams from enhanced oil recovery facilities, or vent streams from storage vessel with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV) that can be sent to the enclosed combustion device or flare. The owner or operator must document in the report in § 60.5420c(b)(10)(v)(I) and the records in § 60.5420c(c)(10)(vi) must note the operating scenario(s) which may lower the NHV of the combined stream through the introduction of inert gases or other vent gas streams which may lower the NHV of the combined stream, and whether the sampling included periods where the highest percentage of inert gases or other vent gas streams which may lower the NHV of the combined stream were sent to the enclosed combustion device or flare. If the introduction of inerts or other vent gas streams which may lower the NHV of the combined stream is intermittent and does not occur during the initial demonstration, the introduction of inerts or other vent gas streams which may lower the NHV of the combined stream will be considered a revision to process operations that triggers a re-evaluation under paragraph (d)(8)(iii)(E) of this section. If conditions at the site did not allow sampling during periods where the introduction of inert gases or other vent gas streams which may lower the NHV of the combined stream was at the highest percentage possible, increasing the percentage of inerts will be considered a revision to process operations that triggers a re-evaluation under paragraph (d)(8)(iii)(E).

(G) You must collect three samples of the inlet gas to the enclosed combustion device or flare at least once every 5 years. The minimum time of collection for each individual sample must be at least one hour when technically feasible. When it is not technically feasible to collect individual samples for at least one hour (*e.g.,* low or intermittent flow), the collection time must be as long as possible up to one hour. For samples taken during low or intermittent flow events, the collection time and the reason for not obtaining a full one hour sample must be documented and reported with the NHV sampling results. The samples must be taken during the period with the lowest expected NHV (*i.e.,* the period with the highest percentage of inerts or other vent gas streams which may lower the NHV of the combined stream). The first set of periodic samples must be taken, or continuous monitoring commenced, no later than 60 calendar months following the last sample taken under paragraph (d)(8)(iii)(A) of this section. Subsequent periodic samples must be taken, or continuous monitoring commenced, no later than 60 calendar months following the previous sample. If any sample has an NHV value less than 1.2 times the applicable operating limit specified in § 60.5415c(e)(1)(vii)(B) or (C) (*i.e.,* values that are less than 240, 360, or 960 Btu/scf, as applicable), you must conduct the continuous monitoring required by one of the options in paragraphs (d)(8)(ii)(A) through (D) of this section within 60 days or receipt of the last sample.

(H) You may request an alternative test method under § 60.5412c(d) to demonstrate that the flare or enclosed combustion device reduces methane and VOC in the gases vented to the device by 95.0 percent by weight or greater. You must measure data values at the frequency specified in the alternative test method and conduct the quality assurance and quality control requirements outlined in the alternative test method at the frequency outlined in the alternative test method. You must monitor the combustion efficiency of the flare continuously for 14 days. If there are no values of the combustion efficiency measured by the alternative test method that are less than 95.0 percent, the gas stream is considered to consistently exceed the applicable NHV operating limit, and you are not required to continuously monitor the NHV of the inlet gas to the flare or enclosed combustion device.

(iv) Except as noted in paragraphs (d)(8)(iv)(A) through (C) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustion device or flare. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as inlet line pressure, line size, and burner nozzle dimensions, to satisfy this requirement. The monitoring instrument must have an accuracy of ±10 percent or better at the maximum expected flow rate.

(A) Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(B) Flares are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you meet the conditions in paragraphs (d)(8)(iv)(B)(*1*) and (*2*) of this section.

(*1*) You must demonstrate, based on the maximum potential pressure of units manifolded to the flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed the maximum tip velocity as specified in the applicable provisions in § 60.18(c) and (f) of this chapter. You must use the minimum expected value of the NHV of the inlet gas to the flare or enclosed combustion based on previous sampling results or process knowledge of the streams sent to the enclosed flare of combustion device in your demonstration. If there are changes to the process or control device that can be reasonably expected to increase the maximum flow rate to the flare, you must conduct a new demonstration to determine whether the maximum flow rate to the flare is compliant with the applicable maximum flare tip velocity provisions in § 60.18(c) and (f) of this chapter.

(*2*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(C) Enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you meet the conditions in paragraphs (d)(8)(iv)(C)(*1*) and (*2*) of this section.

(*1*) You must demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustion device and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustion device cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section to be exceeded. If there are changes to the process or control device that can be reasonably expected to impact the maximum flow rate to the enclosed combustion device, you must conduct a new demonstration to determine whether the maximum flow rate to the enclosed combustor is less than the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section.

(*2*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(v) Conduct inspections monthly and at other times as requested by the Administrator to monitor for visible emissions from the combustion device using section 11 of Method 22 of appendix A to this part or conduct visible emissions monitoring according to paragraph (h) of this section. The observation period shall be 15 minutes or once the amount of time visible emissions is present has exceeded 1 minute. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period.

(e) Calculate the value of the applicable monitored parameter in accordance with paragraphs (e)(1) through (4) of this section.

(1) You must calculate the daily average value for condenser outlet temperature for each operating day, using the data recorded by the monitoring system. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(2) You must use the 5-minute readings from the heat sensing devices to assess the presence of a pilot or combustion flame.

(3) You must use the regeneration cycle time (*i.e.,* duration of the carbon bed steaming cycle) for each regenerative-type carbon adsorption system to calculate the average parameter to compare with the maximum steam mass flow or volumetric flow during each carbon bed regeneration cycle and the maximum carbon bed temperature during the steaming cycle. The carbon bed temperature after the regeneration cycle should not be averaged; you must use the carbon bed temperature measured within 15 minutes of completing the cooling cycle to compare with the minimum carbon bed temperature after the regeneration cycle.

(4) For all operating parameters others than those described in paragraphs (e)(1) through (3) of this section, you must calculate the 3-hour rolling average of each monitored parameter. For each operating hour, calculate the hourly value of the operating parameter from your continuous monitoring system. Average the three most recent hours of data to determine the 3-hour average. Determine the 3-hour rolling average by recalculating the 3-hour average each hour.

(f) * * *

(1) * * *

(iv) If you operate an enclosed combustion device where the combustion zone temperature is not an indicator of destruction efficiency or a control device where the performance test requirement was met under § 60.5413c(d), you must maintain the NHV of the gas sent to the enclosed combustion device above the applicable limits specified in § 60.5412c(a)(1)(iv)(A) through (C).

* * * * *

(g) * * *

(1) A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is below the applicable limits specified in § 60.5415c(e)(1)(vii)(B)(*1*) through (*3*) and (*5*) or above the limit specified in § 60.5415c(e)(1)(vii)(B)(*4*); or for each flare or enclosed combustion device except for boilers and process heaters meeting the requirements in § 60.5412c(a)(1)(iii) and catalytic vapor incinerators meeting the requirements in § 60.5412c(a)(1)(v), when the heat sensing device indicates that there is no pilot or combustion flame present for any time period. If you use a backpressure regulator valve to maintain the inlet gas flow to an enclosed combustion device or flare above the minimum value, a deviation occurs if the annual inspection finds that the backpressure regulator valve set point is not set correctly or indicates that the backpressure regulator valve does not fully close when not in the open position.

* * * * *

(6) For a combustion control device whose model is tested under § 60.5413c(d), a deviation occurs when the conditions of paragraph (g)(4), (5), or (6)(i) through (v) of this section are met.

(i) The hourly inlet gas flow rate is less than the minimum inlet gas flow rate or greater than the maximum inlet gas flow rate determined by the manufacturer. If you use a backpressure regulator valve to maintain the inlet gas flow above the minimum value, a deviation occurs if the annual inspection finds that the backpressure regulator valve set point is not set correctly or indicates that the backpressure regulator valve does not fully close when not in the open position.

(ii) Results of the monthly visible emissions test conducted under § 60.5413c(e)(3) or monitoring under paragraph (h) of this section indicate visible emissions exceed 1 minute in any 15-minute period.

(iii) There is no indication of the presence of a pilot or combustion flame for any 5-minute time period.

(iv) The control device is not maintained in a leak free condition.

(v) The control device is not operated in accordance with the manufacturer's written operating instructions, procedures and maintenance schedule.

(7) For an enclosed combustion device or flare subject to paragraph (d)(8) of this section, a deviation occurs when any of the conditions described by paragraph (g)(1), (4), or (5) of this section are met or when the results of the visible emissions monitoring conducted under paragraph (d)(8)(v) or (h) of this section exceed 1 minute in any 15-minute period.

* * * * *

(i) * * *

(6) * * *

(i) A deviation occurs if the combustion efficiency is less than 95.0 percent.

* * * * *

■ 10. Amend § 60.5420c by revising paragraphs (a)(3),(b), (c), and (d) introductory text to read as follows:

§ 60.5420c What are my notification, reporting, and recordkeeping requirements?

(a) * * *

(3) *Notification to Administrator.* An owner or operator who commences well closure activities must submit the following notices to the Administrator according to the schedule in paragraphs (a)(3)(i) and (ii) of this section. The

notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well at the well site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983. You must submit notifications in portable document format (PDF) following the procedures specified in paragraph (d) of this section.

(i) You must submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site.

(ii) You must submit a notification of the intent to close a well site 60 days before you begin well closure activities.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (13) of this section following the procedure specified in paragraph (b)(14) of this section. You must submit performance test reports as specified in paragraph (b)(11) or (12) of this section, if applicable. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410c. Subsequent annual reports are due no later than the same date each year as the initial annual report. If you own or operate more than one designated facility, you may submit one report for multiple designated facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (13) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period. You must submit the information in paragraph (b)(1)(v) of this section, as applicable, for your well designated facility which undergoes a change of ownership during the reporting period, regardless of whether reporting under paragraphs (b)(2) and (3) of this section is required for the well designated facility.

(1) The general information specified in paragraphs (b)(1)(i) through (v) of this section is required for all reports.

(i) The company name, facility site name associated with the designated facility, U.S. Well ID or U.S. Well ID associated with the designated facility, if applicable, and address of the designated facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each designated facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (b)(1)(iv).

(v) Identification of each well designated facility for which ownership changed due to sale or transfer of ownership including the United States Well Number; the latitude and longitude coordinates of the well designated facility in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the information in paragraph (b)(1)(v)(A) or (B) of this section, as applicable.

(A) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator to which you sold or transferred ownership of the well designated facility identified in this paragraph (b)(1)(v) .

(B) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator from whom you acquired the well designated facility identified in this paragraph (b)(1)(v).

(2) For each well designated facility that is subject to § 60.5390c(a)(1) or (2), your annual report is required to include the information specified in paragraphs (b)(2)(i) and (ii) of this section, as applicable.

(i) For each well designated facility where all gas well liquids unloading operations comply with § 60.5390c(a)(1), your annual report must include the information specified in paragraphs (b)(2)(i)(A) through (C) of this section, as applicable.

(A) Identification of each well designated facility (U.S. Well ID or U.S. Well ID associated with the well designated facility) that conducts a gas well liquid unloading operation during the reporting period using a method that does not vent to the atmosphere and the technology or technique used. If more than one non-venting technology or technique is used, you must identify all of the differing non-venting liquids unloading methods used during the reporting period.

(B) Number of gas well liquids unloading operations conducted during the year where the well designated facility identified in paragraph (b)(2)(i)(A) of this section had unplanned venting to the atmosphere and best management practices were conducted according to your best management practice plan, as required by § 60.5390c(c). If no venting events occurred, the number would be zero. Other reported information required to be submitted where unplanned venting occurs is specified in paragraphs (b)(2)(i)(B)(*1*) and (*2*) of this section.

(*1*) Log of best management practice plan steps used during the unplanned venting to minimize emissions to the maximum extent possible.

(*2*) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(C) The number of liquids unloading events where unplanned emissions are vented to the atmosphere during a gas well liquids unloading operation where you complied with best management practices to minimize emissions to the maximum extent possible.

(ii) For each well designated facility where all gas well liquids unloading operations comply with § 60.5390c(b) and (c) best management practices, your annual report must include the information specified in paragraphs (b)(2)(ii)(A) through (E) of this section.

(A) Identification of each well designated facility that conducts a gas well liquids unloading during the reporting period.

(B) Number of liquids unloading events conducted during the reporting period.

(C) Log of best management practice plan steps used during the reporting period to minimize emissions to the maximum extent possible.

(D) The number of liquids unloading events during the year that best management practices were conducted according to your best management practice plan.

(E) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(3) For each associated gas well at your well designated facility that is subject to § 60.5391c, your annual report is required to include the applicable information specified in paragraphs (b)(3)(i) through (v) of this section, as applicable.

(i) For each associated gas well at your well designated facility that complies with § 60.5391c(a)(1), (2), (3), or (4) your annual report is required to include the information specified in paragraphs (b)(3)(i)(A) and (B) of this section.

(A) An identification of each existing associated gas well that complies with § 60.5391c(a)(1), (2), (3), or (4).

(B) The information specified in paragraphs (b)(3)(i)(B)(*1*) through (*4*) of this section for each incident when the associated gas was temporarily routed to a flare or control device in accordance with § 60.5391c(c).

(*1*) The reason in § 60.5391c(c)(1), (2), (3), or (4) for each incident.

(2) The start date and time of each incident of routing associated gas to the flare or control device, along with the total duration in hours of each incident.

(3) Documentation that all CVS requirements specified in § 60.5411c(a) and (c) and all applicable flare or control device requirements specified in § 60.5412c were met during each period when the associated gas is routed to the flare or control device.

(*4*) For each instance where you route associated gas to a flare or control device beyond 72 hours due to ‘‘exigent circumstances’’ according to § 60.5391c(c)(1) or (2), you must include the record information specified in paragraph (c)(2)(vi) of this section in your annual report.

(ii) For all instances where you temporarily vent the associated gas in accordance with § 60.5391c(d), you must report the information specified in paragraphs (b)(3)(ii)(A) through (D) of this section. This information is required to be reported if you are routinely complying with § 60.5391c(a) or (b) or temporarily complying with § 60.5391c(c). In addition to this information for each incident, you must report the cumulative duration in hours of venting incidents and the cumulative VOC and methane emissions in pounds for all incidents in the calendar year.

(A) The reason in § 60.5391c(d)(1), (2), or (3) for each incident.

(B) The start date and time of each incident of venting the associated gas, along with the total duration in hours of each incident.

(C) The methane emissions in pounds that were emitted during each incident.

(D) The total duration of venting for all incidents in the year, along with the cumulative methane emissions in pounds that were emitted.

(iii) For each associated gas well at your well designated facility that complies with the requirements of § 60.5391c(b) by routing your associated gas to a control device that reduces methane emissions by at least 95.0 percent, your annual report must include the information specified in paragraphs (b)(3)(iii)(A) through (C), and paragraph (D) or (E) of this section. The information in paragraphs (b)(3)(iii)(A) and (B) of this section is only required in the initial annual report.

(A) Identification of the associated gas well using the control device and the information in paragraph (b)(10)(v) of this section.

(B) The information specified in paragraphs (b)(10)(i) through (iv) of this section.

(C) Identification of each instance when associated gas was vented and not routed to a control device that reduces methane emissions by at least 95.0 percent in accordance with paragraph (b)(3)(ii) of this section.

(D) For each associated gas well that complies with the requirements of § 60.5391c(b) because it has demonstrated that annual methane emissions are 40 tons per year or less, provide records of the calculation of annual methane emissions determined in accordance with § 60.5391c(e)(1).

(E) For each associated gas well facility that complies with the requirements of § 60.5391c(b) because it has demonstrated that it is not feasible to comply with § 60.5391c(a)(1), (2), (3), or (4) due to technical reasons, provide each annual demonstration and certification of the technical reason that it is not feasible to comply with § 60.5391c(a)(1) through (4) in accordance with § 60.5391c(b)(2)(i) through (iii).

(iv) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(v) For each deviation recorded as specified in paragraph (c)(2)(vi) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(4) For each centrifugal compressor that is a designated facility, the information specified in paragraphs (b)(4)(i) through (ix) of this section, as applicable.

(i) An identification of each centrifugal compressor.

(ii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(3) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) If complying with § 60.5392c(a)(1) and (2) wet and dry seal centrifugal compressor requirements, the cumulative number of hours of operation since initial startup, since 36 months after the state plan submittal deadline (as specified in § 60.5362c(c)), or since the previous volumetric flow rate measurement, as applicable, which have elapsed prior to conducting your volumetric flow rate measurement or emissions screening.

(iv) A description of the method used and the results of the volumetric emissions measurement or emissions screening, as applicable.

(v) If required to comply with § 60.5392c(a)(5), the information specified in paragraphs (b)(10)(i) through (iv) of this section.

(vi) If complying with § 60.5392c(a)(4) with a control device, identification of the centrifugal compressor with the control device and the information in paragraph (b)(10)(v) of this section.

(vii) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(viii) Number and type of seals on delay of repair and explanation for each delay of repair.

(ix) Date of planned shutdown(s) that occurred during the reporting period if there are any seals that have been placed on delay of repair.

(5) For each reciprocating compressor designated facility, the information specified in paragraphs (b)(5)(i) through (vii) of this section, as applicable.

(i) The cumulative number of hours of operation since initial startup, since 36 months after the state plan submittal deadline (as specified in § 60.5362c(c)), since the previous volumetric flow rate measurement, or since the previous reciprocating compressor rod packing replacement, as applicable, which have elapsed prior to conducting your volumetric flow rate measurement or emissions screening. Alternatively, a statement that emissions from the rod packing are being routed to a process or control device through a closed vent system.

(ii) If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(4)(i) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(iv) If complying with § 60.5393c(d)(1) or (2), the information in paragraphs (b)(10)(i) through (v) of this section.

(v) Number and type of rod packing replacements/repairs on delay of repair and explanation for each delay of repair.

(vi) Date of planned shutdown(s) that occurred during the reporting period if there are any rod packing replacements/repairs that have been placed on delay of repair.

(vii) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(6) For each process controller designated facility, the information specified in paragraphs (b)(6)(i) through (iii) of this section in your initial annual report and in subsequent annual reports for each process controller designated facility that is constructed, modified, or reconstructed during the reporting period. Each annual report must contain the information specified in paragraphs (b)(6)(iv) through (x) of this section for each process controller designated facility.

(i) An identification of each existing process controller that is driven by natural gas, as required by § 60.5394c(d), that allows traceability to the records required in paragraph (c)(5)(i) of this section.

(ii) For each process controller in the designated facility complying with § 60.5394c(a), you must report the information specified in paragraphs (b)(6)(ii)(A) and (B) of this section, as applicable.

(A) An identification of each process controller complying with § 60.5394c(a)(1) by routing the emissions to a process.

(B) An identification of each process controller complying with § 60.5394c(a)(2) by using a self-contained natural gas-driven process controller.

(iii) For each process controller designated facility located at a site in Alaska that does not have access to electrical power and that complies with § 60.5394c(b), you must report the information specified in paragraph (b)(6)(iii)(A), (B), or (C) of this section, as applicable.

(A) For each process controller complying with § 60.5394c(b)(1) process controller bleed rate requirements, you must report the information specified in paragraphs (b)(6)(iii)(A)(*1*) and (*2*) of this section.

(*1*) The identification of process controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh.

(*2*) Where necessary to meet a functional need, the identification and demonstration of why it is necessary to use a process controller with a natural gas bleed rate greater than 6 scfh.

(B) An identification of each intermittent vent process controller complying with the requirements in paragraph § 60.5394c(b)(2).

(C) An identification of each process controller complying with the requirements in § 60.5394c(b) by routing emissions to a control device in accordance with § 60.5394c(b)(3).

(iv) Identification of each process controller which changes its method of compliance during the reporting period and the applicable information specified in paragraphs (b)(6)(v) through (ix) of this section for the new method of compliance.

(v) For each process controller in the designated facility complying with the requirements of § 60.5394c(a) by routing the emissions to a process, you must report the information specified in paragraphs (b)(10)(i) through (iv) of this section.

(vi) For each process controller in the designated facility complying with the requirements of § 60.5394c(a) by using a self-contained natural gas-driven process controller, you must report the information specified in paragraphs (b)(6)(vi)(A) and (B) of this section.

(A) Dates of each inspection required under § 60.5416c(b); and

(B) Each defect or leak identified during each natural gas-driven-self-contained process controller system inspection, and the date of repair or date of anticipated repair if repair is delayed.

(vii) For each process controller in the designated facility complying with the requirements of § 60.5394c(b)(2), you must report the information specified in paragraphs (b)(6)(vii)(A) and (B) of this section.

(A) Dates and results of the intermittent vent process controller monitoring required by § 60.5394c(b)(2)(ii).

(B) For each instance in which monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, the date of repair or replacement or the date of anticipated repair or replacement if the repair or replacement is delayed, and the date and results of the re-survey after repair or replacement.

(viii) For each process controller designated facility complying with § 60.5394c(b)(3) by routing emissions to a control device, you must report the information specified in paragraph (b)(10) of this section.

(ix) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(x) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(6)(ii)(B) and (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(7) For each storage vessel designated facility, the information in paragraphs (b)(7)(i) through (x) of this section.

(i) An identification, including the location, of each existing storage vessel designated facility. The location of the storage vessel designated facility shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the methane emission rate determination according to § 60.5386c(e)(1) for each tank battery that became a designated facility during the reporting period or is returned to service during the reporting period.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(6)(iii) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iv) For each storage vessel designated facility complying with § 60.5396c(a)(2) with a control device, report the identification of the storage vessel designated facility with the control device and the information in paragraph (b)(10)(v) of this section.

(v) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(vi) If required to comply with § 60.5396c(b)(1), the information in paragraphs (b)(10)(i) through (iv) of this section.

(vii) You must identify each storage vessel designated facility that is removed from service during the reporting period as specified in § 60.5396c(c)(1)(ii), including the date the storage vessel designated facility was removed from service. You must identify each storage vessel that that is removed from service from a storage vessel designated facility during the reporting period as specified in § 60.5396c(c)(2)(iii), including identifying the impacted storage vessel designated facility and the date each storage vessel was removed from service.

(viii) You must identify each storage vessel designated facility or portion of a storage vessel designated facility returned to service during the reporting period as specified in § 60.5396c(c)(4), including the date the storage vessel designated facility or portion of a storage vessel designated facility was returned to service.

(ix) You must identify each storage vessel designated facility that no longer complies with § 60.5396c(a)(3) and instead complies with § 60.5396c(a)(2). You must identify whether the change in the method of compliance was due to fracturing or refracturing or whether the change was due to an increase in the monthly emissions determination. If the change was due to an increase in the monthly emissions determination, you must provide documentation of the emissions rate. You must identify the date that you complied with § 60.5396c(a)(2) and must submit the information in (b)(7)(iii) through (vii) of this section.

(x) You must submit a statement that you are complying with § 60.112b(a)(1) or (2), if applicable, in your initial annual report.

(8) For the fugitive emissions components designated facility, report the information specified in paragraphs (b)(8)(i) through (iv) of this section, as applicable.

(i)(A) Designation of the type of site (*i.e.,* well site, centralized production facility, or compressor station) at which the fugitive emissions components designated facility is located.

(B) For the fugitive emissions components designated facility at a well site or centralized production facility that became a designated facility during the reporting period, you must include the date of the startup of production or the date of the first day of production after modification. For the fugitive emissions components designated facility at a compressor station that became a designated facility during the reporting period, you must include the date of startup or the date of modification.

(C) For the fugitive emissions components designated facility at a well site, you must specify what type of well site it is (*i.e.,* single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment).

(D) For the fugitive emissions components designated facility at a well site where during the reporting period you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, you must include the date of the change to status as a wellhead only well site.

(E) For the fugitive emissions components designated facility at a well site where you previously reported under paragraph (b)(8)(i)(D) of this section the removal of all major production and processing equipment and during the reporting period major production and processing equipment is added back to the well site, the date that the first piece of major production and processing equipment is added back to the well site.

(F) For the fugitive emissions components designated facility at a well site where during the reporting period you undertake well closure requirements, the date of the cessation of production from all wells at the well site, the date you began well closure activities at the well site, and the dates of the notifications submitted in accordance with paragraph (a)(3) of this section.

(ii) For each fugitive emissions monitoring survey performed during the annual reporting period, the information specified in paragraphs (b)(8)(ii)(A) through (G) of this section.

(A) Date of the survey.

(B) Monitoring instrument or, if the survey was conducted by visual, audible, or olfactory methods, notation that AVO was used.

(C) Any deviations from the monitoring plan elements under § 60.5397c(c)(1), (2), (7), and (8) or (d) or a statement that there were no deviations from these elements of the monitoring plan.

(D) Number and type of components for which fugitive emissions were detected.

(E) Number and type of fugitive emissions components that were not repaired as required in § 60.5397c(h).

(F) Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair.

(G) Date of planned shutdown(s) that occurred during the reporting period if there are any components that have been placed on delay of repair.

(iii) For well closure activities which occurred during the reporting period, the information in paragraphs (b)(8)(iii)(A) and (B) of this section.

(A) A status report with dates for the well closure activities schedule developed in the well closure plan. If all steps in the well closure plan are completed in the reporting period, the date that all activities are completed.

(B) If an OGI survey is conducted during the reporting period, the information in paragraphs (b)(8)(iii)(B)(*1*) through (*3*) of this section.

(*1*) Date of the OGI survey.

(*2*) Monitoring instrument used.

(*3*) A statement that no fugitive emissions were found, or if fugitive emissions were found, a description of the steps taken to eliminate those emissions, the date of the resurvey, the results of the resurvey, and the date of the final resurvey which detected no emissions.

(iv) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(9) For each pump designated facility, the information specified in paragraphs (b)(9)(i) through (iv) of this section in your initial annual report. Each annual report must contain the information specified in paragraphs (b)(9)(v) through (ix) of this section for each pump designated facility.

(i) The identification of each of your pumps that are driven by natural gas, as required by § 60.5395c(a) that allows traceability to the records required by paragraph (c)(14)(i) of this section.

(ii) For each pump designated facility for which there is a control device on site but it does not achieve a 95.0

percent emissions reduction, the certification that there is a control device available on site but it does not achieve a 95.0 percent emissions reduction required under § 60.5395c(b)(5). You must also report the emissions reduction percentage the control device is designed to achieve.

(iii) For each pump designated facility for which there is no control device or vapor recovery unit on site, the certification required under § 60.5395c(b)(6) that there is no control device or vapor recovery unit on site.

(iv) For each pump designated facility for which it is technically infeasible to route the emissions to a process or control device, the certification of technically infeasibility required under § 60.5395c(b)(7).

(v) For any pump designated facility which has previously reported as required under paragraphs (b)(9)(i) through (iv) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pump designated facility and the date that the pump designated facility meets one of the change conditions described in paragraphs (b)(9)(v)(A) through (C) of this section.

(A) If you install a control device or vapor recovery unit, you must report that a control device or vapor recovery unit has been added to the site and that the pump designated facility now is required to comply with § 60.5395c(b)(1) or (3), as applicable.

(B) If your pump designated facility previously complied with § 60.5395c(b)(1) or (3), as applicable, by routing emissions to a process or a control device and the process or control device is subsequently removed from the site or is no longer available such that there is no ability to route the emissions to a process or control device at the location, or that it is not technically feasible to capture and route the emissions to another control device or process located on site, report that you are no longer complying with the applicable requirements of § 60.5395c(b)(1) or (3) and submit the information provided in paragraph (b)(9)(v)(B)(*1*) or (*2*) of this section.

(*1*) Certification that there is no control device or vapor recovery unit on site.

(*2*) Certification of the engineering assessment that it is technically infeasible to capture and route the emissions to another control device or process located on site.

(C) If any pump affected facility or individual natural gas-driven pump changes its method of compliance during the reporting period other than for the reasons specified in paragraphs (b)(9)(v)(A) and (B) of this section, identify the new compliance method for each natural gas-driven pump within the affected facility which changes its method of compliance during the reporting period and provide the applicable information specified in paragraphs (b)(9)(ii) through (iv) and (vi) through (viii) of this section for the new method of compliance.

(vi) For each pump designated facility complying with the requirements of § 60.5395c(a) or (b)(2) by routing the emissions to a process, you must report the information specified in paragraphs (b)(10)(i) through (iv) of this section.

(vii) For each pump designated facility complying with the requirements of § 60.5395c(b)(3) by routing the emissions to a control device, you must report the information required under paragraph (b)(10) of this section.

(viii) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(ix) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(10) For each well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment designated facility which uses a closed vent system routed to a control device to meet the emissions reduction standard, you must submit the information in paragraphs (b)(10)(i) through (v) of this section. For each centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, or process unit equipment which uses a closed vent system to route to a process, you must submit the information in paragraphs (b)(10)(i) through (iv) of this section. For each centrifugal compressor, reciprocating compressor, and storage vessel equipped with a cover, you must submit the information in paragraphs (b)(10)(i) and (ii).

(i) Dates of each inspection required under § 60.5416c(a) and (b).

(ii) Each defect or emissions identified during each inspection and the date of repair or the date of anticipated repair if the repair is delayed.

(iii) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416c(a)(4).

(iv) You must submit the certification signed by the qualified professional engineer or in-house engineer according to § 60.5411c(c) for each closed vent system routing to a control device or process in the reporting year in which the certification is signed.

(v) If you comply with the emissions standard for your well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment designated facility with a control device, the information in paragraphs (b)(10)(v)(A) through (L) of this section, unless you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412c(d). If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412c(d), the information in paragraphs (b)(10)(v)(A) through (C) and (L) through (P) of this section.

(A) Identification of the control device.

(B) Make, model, and date of installation of the control device.

(C) Identification of the designated facility controlled by the device.

(D) For each continuous parameter monitoring system used to demonstrate compliance for the control device, a unique continuous parameter monitoring system identifier and the make, model number, and date of last calibration check of the continuous parameter monitoring system.

(E) For each instance where there is a deviation of the control device in accordance with § 60.5417c(g)(1) through (3) or (5) through (7) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (*e.g.,* NHV operating limit, lack of pilot or combustion flame, condenser efficiency, bypass line flow, visible emissions), and cause of the deviation.

(F) For each instance where there is a deviation of the continuous parameter monitoring system in accordance with § 60.5417c(g)(4) include the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation.

(G) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test or observation of the video surveillance output, the length of the observation in minutes, and the number of minutes for which visible emissions were present.

(H) If a performance test was conducted on the control device during the reporting period, provide the date the performance test was conducted. Submit the performance test report following the procedures specified in paragraph (b)(11) of this section.

(I) An indication of whether the enclosed combustion device or flare receives inert gases or other vent streams which may lower the NHV of the combined stream, and if so, a description of the operating scenario(s) which may lower the NHV of the combined stream through the introduction of inert gases or other vent gas streams. If a demonstration of the NHV of the inlet gas to the enclosed combustion device or flare was conducted during the reporting period in accordance with § 60.5417c(d)(8)(iii), an indication of whether this is a re-evaluation of vent gas NHV and the reason for the re-evaluation; the applicable required minimum vent gas NHV; if twice daily samples of the vent stream were taken, the number of samples with NHV values that are less than 1.2 times the applicable required minimum NHV, an indication of whether full one hour samples were collected or if shorter sampling times and, if shorter sampling times were used, the collection time(s) used and the reason for not obtaining a full one hour sample; if continuous NHV sampling of the vent stream was conducted, the number of hourly block average NHV values that are less than the required minimum vent gas NHV; if continuous combustion efficiency monitoring was conducted using an alternative test method approved under § 60.5412c(d), the number of values of the combustion efficiency that were less than 95.0 percent; the resulting determination of whether continuous NHV monitoring is required or not in accordance with § 60.5417c(d)(8)(iii)(D), (E), or (H); and if the enclosed combustion device or flare received inert gases or other vent streams which may lower the NHV of the combined stream, whether the sampling included periods where the highest percentage of inert gases or other vent streams which may lower the NHV of the combined stream were sent to the enclosed combustion device or flare.

(J) If a demonstration was conducted in accordance with § 60.5417c(d)(8)(iv) that the maximum potential pressure of units manifolded to an enclosed combustion device or flare cannot cause the maximum inlet flow rate established in accordance with § 60.5417c(f)(1) or a flare tip velocity limit of 18.3 meter/second (60 feet/second) to be exceeded, an indication of whether this is a re-evaluation of the gas flow and the reason for the re-evaluation; the demonstration conducted; and applicable engineering calculations.

(K) For each periodic sampling event conducted under § 60.5417c(d)(8)(iii)(G), provide the date of the sampling, the required minimum vent gas NHV, and the NHV value for each vent gas sample.

(L) For each flare and enclosed combustion device, provide the date each device is observed with OGI in accordance with § 60.5415c(e)(1)(x) and whether uncombusted emissions were present. Provide the date each device was visibly observed during an AVO inspection in accordance with § 60.5415c(e)(1)(x), whether the pilot or combustion flame was lit at the time of observation, and whether the device was found to be operating properly.

(M) An identification of the alternative test method used.

(N) For each instance where there is a deviation of the control device in accordance with § 60.5417c(i)(6)(i) or (iii) through (v) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (*e.g.,* destruction efficiency below 95 percent, lack of pilot or combustion flame, visible emissions), and cause of the deviation.

(O) For each instance where there is a deviation of the data availability in accordance with § 60.5417c(i)(6)(ii) include the date of each operating day when monitoring data are not available for at least 75 percent of the operating hours.

(P) If no deviations occurred under paragraph (b)(10)(v)(N) or (O) of this section, a statement that there were no deviations for the control device during the annual report period.

(Q) Any additional information required to be reported as specified by the Administrator as part of the alternative test method approval under § 60.5412c(d).

(11) Within 60 days after the date of completing each performance test (see § 60.8) required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413c(d), you must submit the results of the performance test following the procedures specified in paragraph (d) of this section. Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

(12) For combustion control devices tested by the manufacturer in accordance with § 60.5413c(d), an electronic copy of the performance test results required by § 60.5413c(d) shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.*

(13) If you had a super-emitter event during the reporting period, the start date of the super-emitter event, the duration of the super-emitter event in hours, and the designated facility associated with the super-emitter event, if applicable.

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

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (14) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. 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.

(1) For each gas well liquids unloading operation at your well designated facility that is subject to § 60.5390c(a)(1) or (2), the records of each gas well liquids unloading operation conducted during the reporting period, including the information specified in paragraphs (c)(1)(i) through (iii) of this section, as applicable.

(i) For each gas well liquids unloading operation that complies with § 60.5390c(a)(1) by performing all liquids unloading events without venting of methane emissions to the atmosphere, comply with the recordkeeping requirements specified in paragraphs (c)(1)(i)(A) and (B) of this section.

(A) Identification of each well (*i.e.,* U.S. Well ID or U.S. Well ID associated with the well designated facility) that conducts a gas well liquids unloading operation during the reporting period without venting of methane emissions and the non-venting gas well liquids unloading method used. If more than one non-venting method is used, you must maintain records of all the differing non-venting liquids unloading methods used at the well designated facility complying with § 60.5390c(a)(1).

(B) Number of events where unplanned emissions are vented to the atmosphere during a gas well liquids unloading operation where you complied with best management practices to minimize emissions to the maximum extent possible.

(ii) For each gas well liquids unloading operation that complies with § 60.5390c(b) and (c) best management practices, maintain records documenting information specified in paragraphs (c)(1)(ii)(A) through (D) of this section.

(A) Identification of each well designated facility that conducts liquids unloading during the reporting period that employs best management practices to minimize emissions to the maximum extent possible.

(B) Documentation of your best management practice plan developed under paragraph § 60.5390c(c). You may update your best management practice plan to include additional steps which meet the criteria in § 60.5390c(c).

(C) A log of each best management practice plan step taken to minimize emissions to the maximum extent possible for each gas well liquids unloading event.

(D) Documentation of each gas well liquids unloading event where deviations from your best management practice plan steps occurred, the date and time the deviation began, the duration of the deviation, documentation of best management practice plans steps were not followed, and the steps taken in lieu of your best management practice plan steps during those events to minimize emissions to the maximum extent possible.

(iii) For each well designated facility that reduces methane emissions from well designated facility gas wells that unload liquids by 95.0 percent by routing emissions to a control device through closed vent system under § 60.5390c(g), you must maintain the records in paragraphs (c)(1)(iii)(A) through (E) of this section.

(A) If you comply with the emission reduction standard with a control device, the information for each control device in paragraph (c)(10) of this section.

(B) Records of the closed vent system inspection as specified paragraph in (c)(7) of this section.

(C) Records of the cover inspections as specified in paragraph (c)(8) of this section.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(9) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(11) of this section.

(2) For each associated gas well, you must maintain the applicable records specified in paragraphs (c)(2)(i) or (ii) and (iii), (iv), (v), (vi) and (vii) of this section, as applicable.

(i) For each associated gas well that complies with the requirements of § 60.5391c(a)(1), (2), (3), or (4), you must keep the records specified in paragraphs (c)(2)(i)(A) and (B) of this section.

(A) Documentation of the specific method(s) in § 60.5391c(a)(1), (2), (3), or (4) that was used.

(B) For instances where you temporarily route the associated gas to a flare or control device in accordance with § 60.5391c(c), you must keep the records specified in paragraphs (c)(2)(i)(B)(*1*) through (*3*) of this section.

(*1*) The reason in § 60.5391c(c)(1), (2), (3), or (4) for each incident.

(2) The date of each incident, along with the times when routing the associated gas to the flare or control device started and ended, along with the total duration of each incident.

(3) Documentation that all CVS requirements specified in § 60.5411c(a) and (c) and all applicable flare or control device requirements specified in § 60.5412c are met during each period when the associated gas is routed to the flare or control device.

(ii) For instances where you temporarily vent the associated gas in accordance with § 60.5391c(d), you must keep the records specified in paragraphs (c)(2)(ii)(A) through (D) of this section. These records are required if you are routinely complying with § 60.5391c(a) or § 60.5391c(b) or temporarily complying with § 60.5391c(c).

(A) The reason in § 60.5391c(d)(1), (2), or (3) for each incident.

(B) The date of each incident, along with the times when venting the associated gas started and ended, along with the total duration of each incident.

(C) The methane emissions that were emitted during each incident.

(D) The cumulative duration of venting incidents and methane emissions for all incidents in each calendar year.

(iii) For each associated gas well that complies with the requirements of § 60.5391c(b) because it has demonstrated that annual methane emissions are 40 tons per year or less at the initial compliance date, maintain records of the calculation of annual methane emissions determined in accordance with § 60.5391c(e)(1).

(iv) For each associated gas well at your well that complies with the requirements of § 60.5391c(b) because it has demonstrated that it is not feasible to comply with § 60.5391c(a)(1), (2), (3), or (4) due to technical reasons, records of each annual demonstration and certification of the technical reason that it is not feasible to comply with § 60.5391c(a)(1) through (4) in accordance with § 60.5391c(b)(2)(i) through (iii), as well as the records required by paragraph (c)(2)(v) of this section.

(v) For each associated gas well that complies with the requirements of § 60.5391c(b) by routing your associated gas to a flare or control device that achieves a 95.0 reduction in methane emissions, the records in paragraphs (c)(2)(v)(A) through (E) of this section.

(A) Identification of each instance when associated gas was vented and not routed to a control device that reduces methane emissions by at least 95.0 percent in accordance with paragraph (c)(2)(iii) of this section.

(B) If you comply with the emission reduction standard in § 60.5391c with a control device, the information for each control device in paragraph (c)(10) of this section.

(C) Records of the closed vent system inspection as specified in paragraph (c)(7) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (c)(7) of this section, you must maintain records of the information specified in § 60.5424c.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(9) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(11) of this section.

(vi) For each instance where you route associated gas to a flare or control device for beyond 72 hours due to an ''exigent circumstance'' according to § 60.5391c(c)(1) or (2), you must maintain the records specified in paragraphs (c)(2)(vi)(A) through (D) of this section.

(A) A written description of the ''exigent circumstance'' requiring the need to flare or route to a control device beyond 72 hours.

(B) A description of steps taken to resolve the need for temporary flaring/routing to a control device;

(C) The dates and times an identified ''exigent circumstance'' started and ended (*e.g.,* when owners or operators are able to access site, when personnel and/or equipment are available) and the total duration of each ''exigent circumstance''; and

(D) The dates and times temporary flaring/routing to a control device started and ended and the total duration of temporary flaring/routing to a control device due to the identified ''exigent circumstance.''

(vii) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(3) For each centrifugal compressor designated facility, you must maintain the records specified in paragraphs (c)(3)(i) through (iii) of this section.

(i) For each centrifugal compressor designated facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5392c, including a description of each deviation, the date and time each deviation began and the duration of each deviation.

(ii) For each wet seal compressor complying with the emissions reduction standard in § 60.5392c(a)(3) and (4), you must maintain the records in paragraphs (c)(3)(ii)(A) through (E) of this section. For each wet seal compressor complying with the alternative standard in § 60.5392c(a)(3) and (5) by routing the closed vent system to a process, you must maintain the records in paragraphs (c)(3)(ii)(B) through (E) of this section.

(A) If you comply with the emission reduction standard in § 60.5392c(a)(3) and (4) with a control device, the information for each control device in paragraph (c)(10) of this section.

(B) Records of the closed vent system inspection as specified in paragraph (c)(7) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (c)(7) of this section, you must maintain records of the information specified in § 60.5424c.

(C) Records of the cover inspections as specified in paragraph (c)(8) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraph (c)(8) of this section, you must maintain the information specified in § 60.5424c.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(9) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(11) of this section.

(iii) For each centrifugal compressor designated facility using dry seals or wet seals and each self-contained wet seal centrifugal compressor and complying with the standard in § 60.5392c(a)(1) and (2), you must maintain the records specified in paragraphs (c)(3)(iii)(A) through (H) of this section.

(A) Records of the cumulative number of hours of operation since initial startup, since 36 months after the state plan submittal deadline (as specified in § 60.5362c(c)), or since the previous volumetric flow rate measurement, as applicable.

(B) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(C) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(3)(iii)(C)(*1*) through (*6*) of this section.

(*1*) Description of standard method published by a consensus-based standards organization or industry standard practice.

(*2*) Records of volumetric flow rate emissions calculations conducted according to § 60.5392c(a)(2), as applicable.

(*3*) Records of manufacturer operating procedures and measurement methods.

(*4*) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration and accuracy checks.

(*5*) Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

(*6*) Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

(D) Date when performance-based volumetric flow rate is exceeded.

(E) The date of successful repair of the compressor seal, including follow-up performance-based volumetric flow rate measurement to confirm successful repair.

(F) Identification of each compressor seal placed on delay of repair and explanation for each delay of repair.

(G) For each compressor seal or part needed for repair placed on delay of repair because of replacement seal or part unavailability, the operator must document: the date the seal or part was added to the delay of repair list, the date the replacement seal or part was ordered, the anticipated seal or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the seal or part.

(H) Date of planned shutdowns that occur while there are any seals or parts that have been placed on delay of repair.

(4) For each reciprocating compressor designated facility, you must maintain the records in paragraphs (c)(4)(i) through (x) and (c)(7) through (12) of this section, as applicable. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraph (c)(7) of this section, you must provide the information specified in § 60.5424c.

(i) For each reciprocating compressor designated facility, you must maintain records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5393c, including a description of each deviation, the date and time each deviation began and the duration of each deviation in hours.

(ii) Records of the date of installation of a rod packing emissions collection system and closed vent system as specified in § 60.5393c(d), where applicable.

(iii) Records of the cumulative number of hours of operation since initial startup, since 36 months after the state plan submittal deadline (as specified in § 60.5362c(c)), or since the previous volumetric flow rate measurement, as applicable. Alternatively, a record that emissions from the rod packing are being routed to a process through a closed vent system.

(iv) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(v) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(4)(v)(A) through (F) of this section.

(A) Description of standard method published by a consensus-based standards organization or industry standard practice.

(B) Records of volumetric flow rate calculations conducted according to § 60.5393c(b) or (c), as applicable.

(C) Records of manufacturer's operating procedures and measurement methods.

(D) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration and accuracy checks.

(E) Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

(F) Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

(vi) Date when performance-based volumetric flow rate is exceeded.

(vii) The date of successful replacement or repair of reciprocating compressor rod packing, including follow-up performance-based volumetric flow rate measurement to confirm successful repair.

(viii) Identification of each reciprocating compressor placed on delay of repair because of rod packing or part unavailability and explanation for each delay of repair.

(ix) For each reciprocating compressor that is placed on delay of repair because of replacement rod packing or part unavailability, the operator must document: the date the rod packing or part was added to the delay of repair list, the date the replacement rod packing or part was ordered, the anticipated rod packing or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the rod packing or part.

(x) Date of planned shutdowns that occur while there are any reciprocating compressors that have been placed on delay of repair due to the unavailability of rod packing or parts to conduct repairs.

(5) For each process controller designated facility, you must maintain the records specified in paragraphs (c)(5)(i) through (vii) of this section.

(i) Records identifying each process controller that is driven by natural gas and that does not function as an emergency shutdown device.

(ii) For each process controller designated facility complying with § 60.5394c(a), you must maintain records of the information specified in paragraphs (c)(5)(ii)(A) and (B) of this section, as applicable.

(A) If you are complying with § 60.5394c(a) by routing process controller vapors to a process through a closed vent system, you must report the information specified in paragraphs (c)(5)(ii)(A)(*1*) and (*2*) of this section.

(*1*) An identification of all the natural gas-driven process controllers in the process controller designated facility for which you collect and route vapors to a process through a closed vent system.

(*2*) The records specified in paragraphs (c)(7), (9), and (11) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraph (c)(7) of this section, you must provide the information specified in § 60.5424c.

(B) If you are complying with § 60.5394c(a) by using a self-contained natural gas-driven process controller, you must report the information specified in paragraphs (c)(5)(ii)(B)(*1*) through (*3*) of this section.

(*1*) An identification of each process controller complying with § 60.5394c(a) by using a self-contained natural gas-driven process controller;

(*2*) Dates of each inspection required under § 60.5416c(b); and

(*3*) Each defect or leak identified during each natural gas-driven-self-contained process controller system inspection, and date of repair or date of anticipated repair if repair is delayed.

(iii) For each process controller designated facility complying with § 60.5394c(b)(1) process controller bleed rate requirements, you must maintain records of the information specified in paragraphs (c)(5)(iii)(A) and (B) of this section.

(A) The identification of process controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh and records of the manufacturer's specifications indicating that the process controller is designed with a natural gas bleed rate of less than or equal to 6 scfh.

(B) Where necessary to meet a functional need, the identification of the process controller and demonstration of why it is necessary to use a process controller with a natural gas bleed rate greater than 6 scfh.

(iv) For each intermittent vent process controller in the designated facility complying with the requirements in § 60.5394c(b)(2), you must keep records of the information specified in paragraphs (c)(5)(iv)(A) through (C) of this section.

(A) The identification of each intermittent vent process controller.

(B) Dates and results of the intermittent vent process controller monitoring required by § 60.5394c(b)(2)(ii).

(C) For each instance in which monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, the date of repair or replacement, or the date of anticipated repair or replacement if the repair or replacement is delayed and the date and results of the re-survey after repair or replacement.

(v) For each process controller designated facility complying with § 60.5394c(b)(3), you must maintain the records specified in paragraphs (c)(5)(v)(A) and (B) of this section.

(A) An identification of each process controller for which emissions are routed to a control device.

(B) Records specified in paragraphs (c)(7) and (9) through (12) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (c)(7) of this section, you must provide the information specified in § 60.5424c.

(vi) Records of each change in compliance method, including identification of each natural gas-driven process controller which changes its method of compliance, the new method of compliance, and the date of the change in compliance method.

(vii) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(6) For each storage vessel designated facility, you must maintain the records identified in paragraphs (c)(6)(i) through (vii) of this section.

(i) You must maintain records of the identification and location in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983 of each storage vessel designated facility.

(ii) Records of each methane emissions determination for each storage vessel designated facility made under § 60.5386c(e) including identification of the model or calculation methodology used to calculate the methane emission rate.

(iii) For each instance where the storage vessel was not operated in compliance with the requirements specified in § 60.5396c, a description of the deviation, the date and time each deviation began, and the duration of the deviation.

(iv) If complying with the emissions reduction standard in § 60.5396c(a)(1), you must maintain the records in paragraphs (c)(6)(iv)(A) through (E) of this section.

(A) If you comply with the emission reduction standard with a control device, the information for each control device in paragraph (c)(10) of this section.

(B) Records of the closed vent system inspection as specified in paragraph (c)(7) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraph (c)(7) of this section, you must provide the information specified in § 60.5424c.

(C) Records of the cover inspections as specified in paragraph (c)(8) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424c.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(9) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(11) of this section.

(v) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), records indicating the number of consecutive days that the vessel is located at a site in the crude oil and natural gas source category. If a storage vessel is removed from a site and, within 30 days, is either returned to the site or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(vi) Records of the date that each storage vessel designated facility or portion of a storage vessel designated facility is removed from service and returned to service, as applicable.

(vii) Records of the date that liquids from the well following fracturing or refracturing are routed to the storage vessel designated facility; or the date that you comply with paragraph § 60.5396c(a)(2), following a monthly emissions determination which indicates that methane emissions increase to 14 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel designated facility, and records of the methane emissions rate and the model or calculation methodology used to calculate the methane emission rate.

(7) Records of each closed vent system inspection required under § 60.5416c(a)(1) and (2) and (b) for your well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, and process unit equipment designated facility as required in paragraphs (c)(7)(i) through (iv) of this section.

(i) A record of each closed vent system inspection or no identifiable emissions monitoring survey. You must include an identification number for each closed vent system (or other unique identification description selected by you), the date of the inspection, and the method used to conduct the inspection (*i.e.,* visual, AVO, OGI, Method 21 of appendix A–7 to this part).

(ii) For each defect or emissions detected during inspections required by § 60.5416c(a)(1) and (2), or (b) you must record the location of the defect or emissions; a description of the defect; the maximum concentration reading obtained if using Method 21 of appendix A–7 to this part; the indication of emissions detected by AVO if using AVO; the date of detection; the date of each attempt to repair the emissions or defect; the corrective action taken during each attempt to repair the defect; and the date the repair to correct the defect or emissions is completed.

(iii) If repair of the defect is delayed as described in § 60.5416c(b)(6), you must record the reason for the delay and the date you expect to complete the repair.

(iv) Parts of the closed vent system designated as unsafe to inspect as described in § 60.5416c(b)(7) or difficult to inspect as described in § 60.5416c(b)(8), the reason for the designation, and written plan for inspection of that part of the closed vent system.

(8) A record of each cover inspection required under § 60.5416c(a)(3) for your centrifugal compressor, reciprocating compressor, or storage vessel as required in paragraphs (c)(8)(i) through (iv) of this section.

(i) A record of each cover inspection. You must include an identification number for each cover (or other unique identification description selected by you), the date of the inspection, and the method used to conduct the inspection (*i.e.,* AVO, OGI, Method 21 of appendix A–7 to this part).

(ii) For each defect detected during the inspection you must record the location of the defect; a description of the defect; the date of detection; the maximum concentration reading obtained if using Method 21 of appendix A–7 to this part; the indication of emissions detected by AVO if using AVO; the date of each attempt to repair the defect; the corrective action taken during each attempt to repair the defect; and the date the repair to correct the defect is completed.

(iii) If repair of the defect is delayed as described in § 60.5416c(b)(5), you must record the reason for the delay and the date you expect to complete the repair.

(iv) Parts of the cover designated as unsafe to inspect as described in § 60.5416c(b)(7) or difficult to inspect as described in § 60.5416c(b)(8), the reason for the designation, and written plan for inspection of that part of the cover.

(9) For each bypass subject to the bypass requirements of § 60.5416c(a)(4), you must maintain a record of the following, as applicable: readings from the flow indicator; each inspection of the seal or closure mechanism; the date and time of each instance the key is checked out; date and time of each instance the alarm is sounded.

(10) Records for each control device used to comply with the emission reduction standard in § 60.5391c(b) for associated gas wells, § 60.5392c(a)(4) for centrifugal compressor designated facilities, § 60.5393c(d)(2) for reciprocating compressor designated facilities, § 60.5394c(b)(3) for your process controller designated facility in Alaska, § 60.5395c(b)(3) for your pump designated facility, § 60.5396c(a)(2) for your storage vessel designated facility, § 60.5390c(g) for well designated facility gas well liquids unloading, or § 60.5400c(f) or 60.5401c(e) for your process equipment designated facility, as required in paragraphs (c)(10)(i) through (viii) of this section. If you use

an enclosed combustion device or flare using an alternative test method approved under § 60.5412c(d), keep records of the information in paragraph (c)(10)(ix) of this section, in lieu of the records required by paragraphs (c)(10)(i) through (iv) and (vi) through (viii) of this section.

(i) For a control device tested under § 60.5413c(d) which meets the criteria in § 60.5413c(d)(11) and (e), keep records of the information in paragraphs (c)(10)(i)(A) through (E) of this section, in addition to the records in paragraphs (c)(10)(ii) through (ix) of this section, as applicable.

(A) Serial number of purchased device and copy of purchase order.

(B) Location of the designated facility associated with the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(C) Minimum and maximum inlet gas flow rate specified by the manufacturer.

(D) Records of the maintenance and repair log as specified in § 60.5413c(e)(4), for all inspection, repair, and maintenance activities for each control device failing the visible emissions test.

(E) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(ii) For all control devices, keep records of the information in paragraphs (c)(10)(ii)(A) through (G) of this section, as applicable.

(A) Make, model, and date of installation of the control device, and identification of the designated facility controlled by the device.

(B) Records of deviations in accordance with § 60.5417c(g)(1) through (7), including a description of the deviation, the date and time the deviation began, the duration of the deviation, and the cause of the deviation.

(C) The monitoring plan required by § 60.5417c(c)(2).

(D) Make and model number of each continuous parameter monitoring system.

(E) Records of minimum and maximum operating parameter values, continuous parameter monitoring system data (including records that the pilot or combustion flame is present at all times), calculated averages of continuous parameter monitoring system data, and results of all compliance calculations.

(F) Records of continuous parameter monitoring system equipment performance checks, system accuracy audits, performance evaluations, or other audit procedures and results of all inspections specified in the monitoring plan in accordance with § 60.5417c(c)(2). Records of calibration gas cylinders, if applicable.

(G) Periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities. Records of repairs on the monitoring system.

(iii) For each carbon adsorption system, records of the schedule for carbon replacement as determined by the design analysis requirements of § 60.5413c(c)(2) and (3) and records of each carbon replacement as specified in §§ 60.5412c(c)(1) and 60.5415c(e)(1)(viii).

(iv) For enclosed combustion devices and flares, records of visible emissions observations as specified in paragraph (c)(10)(iv)(A) or (B) of this section.

(A) Records of observations with Method 22 of appendix A–7 to this part, including observations required following return to operation from a maintenance or repair activity, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22–1 in Method 22 of appendix A–7 to this part.

(B) If you monitor visible emissions with a video surveillance camera, location of the camera and distance to emission source, records of the video surveillance output, and documentation that an operator looked at the feed daily, including the date and start time of observation, the length of observation, and length of time visible emissions were present.

(v) For enclosed combustion devices and flares, video of the OGI inspection conducted in accordance with § 60.5415c(e)(1)(x). Records documenting each enclosed combustion device and flare was visibly observed during each inspection conducted under § 60.5397c using AVO in accordance with § 60.5415c(e)(1)(x).

(vi) For enclosed combustion devices and flares, an indication of whether the enclosed combustion device or flare receives inert gases or other vent streams which may lower the NHV of the combined stream, and if so, a description of the operating scenario(s) which may lower the NHV of the combined stream through the introduction of inert gases or other vent gas streams. Records of each demonstration of the NHV of the inlet gas to the enclosed combustion device or flare conducted in accordance with § 60.5417c(d)(8)(iii), including the sampling approach used (continuous NHV, twice daily sampling, alternative method), the date, time and results of each analysis, and, if shorter sampling times were used with twice daily sampling, the collection time(s) used and the reason for not obtaining a full one hour sample. For each re-evaluation of the NHV of the inlet gas, records of process changes and explanation of the conditions that led to the need to re-evaluation the NHV of the inlet gas. For each demonstration where the enclosed combustion device or flare received inert gases, record the highest percentage of inert gases that can be sent to the enclosed combustion device or flare and the highest percent of inert gases sent to the enclosed combustion device or flare during the NHV demonstration. Records of periodic sampling conducted under § 60.5417c(d)(8)(iii)(G).

(vii) For enclosed combustion devices and flares, if you use a backpressure regulator valve, the make and model of the valve, date of installation, and record of inlet flow rating. Maintain records of the engineering evaluation and manufacturer specifications that identify the pressure set point corresponding to the minimum inlet gas flow rate, the annual confirmation that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications, and the annual confirmation that the backpressure regulator valve fully closes when not in open position.

(viii) For enclosed combustion devices and flares, records of each demonstration required under § 60.5417c(d)(8)(iv).

(ix) If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412c(d), keep records of the information in paragraphs (c)(10)(ix)(A) through (H) of this section, in lieu of the records required by paragraphs (c)(10)(i) through (iv) and (vi) through (viii) of this section.

(A) An identification of the alternative test method used.

(B) Data recorded at the intervals required by the alternative test method.

(C) Monitoring plan required by § 60.5417c(i)(2).

(D) Quality assurance and quality control activities conducted in accordance with the alternative test method.

(E) If required by § 60.5412c(d)(4) to conduct visible emissions observations, records required by paragraph (c)(10)(iv) of this section.

(F) If required by § 60.5412c(d)(5) to conduct pilot or combustion flame monitoring, record indicating the presence of a pilot or combustion flame and periods when the pilot or combustion flame is absent.

(G) For each instance where there is a deviation of the control device in accordance with § 60.5417c(i)(6)(i) through (v), the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation.

(H) Any additional information required to be recorded as specified by the Administrator as part of the alternative test method approval under § 60.5412c(d).

(11) For each closed vent system routing to a control device or process, the records of the assessment conducted according to § 60.5411c(c):

(i) A copy of the assessment conducted according to § 60.5411c(c)(1); and

(ii) A copy of the certification according to § 60.5411c(c)(1)(i) and (ii).

(12) A copy of each performance test submitted under paragraph (b)(11) or (12) of this section.

(13) For the fugitive emissions components designated facility, maintain the records identified in paragraphs (c)(13)(i) through (vii) of this section.

(i) The date of the startup of production or the date of the first day of production after modification for the fugitive emissions components designated facility at a well site and the date of startup or the date of modification for the fugitive emissions components designated facility at a compressor station.

(ii) For the fugitive emissions components designated facility at a well site, you must maintain records specifying what type of well site it is (*i.e.,* single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment).

(iii) For the fugitive emissions components designated facility at a well site where you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, record the date the well site completes the removal of all major production and processing equipment from the well site, and, if the well site is still producing, record the well ID or separate tank battery ID receiving the production from the well site. If major production and processing equipment is subsequently added back to the well site, record the date that the first piece of major production and processing equipment is added back to the well site.

(iv) The fugitive emissions monitoring plan as required in § 60.5397c(b) through (d).

(v) The records of each monitoring survey as specified in paragraphs (c)(13)(v)(A) through (I) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s), training, and experience of the operator(s) performing the survey.

(D) Monitoring instrument or method used.

(E) Fugitive emissions component identification when Method 21 of appendix A–7 to this part is used to perform the monitoring survey.

(F) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey. For compressor stations, operating mode of each compressor (*i.e.,* operating, standby pressurized, and not operating-depressurized modes) at the station at the time of the survey.

(G) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(H) Records of calibrations for the instrument used during the monitoring survey.

(I) Documentation of each fugitive emission detected during the monitoring survey, including the information specified in paragraphs (c)(13)(v)(I)(*1*) through (*9*) of this section.

(*1*) Location of each fugitive emission identified.

(*2*) Type of fugitive emissions component, including designation as difficult-to-monitor or unsafe-to-monitor, if applicable.

(*3*) If Method 21 of appendix A–7 to this part is used for detection, record the component ID and instrument reading.

(*4*) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph or video must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture). The digital photograph or identification (*e.g.,* tag) may be removed after the repair is completed, including verification of repair with the resurvey.

(*5*) The date of first attempt at repair of the fugitive emissions component(s).

(*6*) The date of successful repair of the fugitive emissions component, including the resurvey to verify repair and instrument used for the resurvey.

(*7*) Identification of each fugitive emission component placed on delay of repair and explanation for each delay of repair.

(*8*) For each fugitive emission component placed on delay of repair for reason of replacement component unavailability, the operator must document: the date the component was added to the delay of repair list, the date the replacement fugitive component or part thereof was ordered, the anticipated component delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the component.

(*9*) Date of planned shutdowns that occur while there are any components that have been placed on delay of repair.

(vi) For well closure activities, you must maintain the information specified in paragraphs (c)(13)(vi)(A) through (G) of this section.

(A) The well closure plan developed in accordance with § 60.5397c(l) and the date the plan was submitted.

(B) The notification of the intent to close the well site and the date the notification was submitted.

(C) The date of the cessation of production from all wells at the well site.

(D) The date you began well closure activities at the well site.

(E) Each status report for the well closure activities reported in paragraph (b)(8)(iv)(A) of this section.

(F) Each OGI survey reported in paragraph (b)(8)(iv)(B) of this section including the date, the monitoring instrument used, and the results of the survey or resurvey.

(G) The final OGI survey video demonstrating the closure of all wells at the site. The video must include the date that the video was taken and must identify the well site location by latitude and longitude.

(vii) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (c)(13)(iv) and (v) of this section, you must maintain the records specified in § 60.5424c.

(14) For each pump designated facility, you must maintain the records identified in paragraphs (c)(14)(i) through (ix) of this section, as applicable.

(i) Identification of each pump that is driven by natural gas and that is in operation 90 days or more per calendar year.

(ii) If you are complying with § 60.5395c(a) or (b)(1) by routing pump vapors to a process through a closed vent system, identification of all the natural gas-driven pumps in the pump designated facility for which you collect and route vapors to a process through a closed vent system and the records specified in paragraphs (c)(7), (9), and (11) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398c, in lieu of the information specified in paragraph (c)(7) of this section, you must provide the information specified in § 60.5424c.

(iii) If you are complying with § 60.5395c(b)(1) by routing pump vapors to control device achieving a 95.0 percent reduction in methane emissions, you must keep the records specified in paragraphs (c)(7) and (9) through (12) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398c, in lieu of the information specified in paragraph (c)(7), you must provide the information specified in § 60.5424c.

(iv) If you are complying with § 60.5395c(b)(3) by routing pump vapors to a control device achieving less than a 95.0 percent reduction in methane emissions, you must maintain records of the certification that there is a control device on site but it does not achieve a 95.0 percent emissions reduction and a record of the design evaluation or manufacturer's specifications which indicate the percentage reduction the control device is designed to achieve.

(v) If you have less than three natural gas-driven diaphragm pumps in the pump designated facility, and you do not have a vapor recovery unit or control device installed on site by the compliance date, you must retain a record of your certification required under § 60.5395c(b)(4), certifying that there is no vapor recovery unit or control device on site. If you subsequently install a control device or vapor recovery unit, you must maintain the records required under paragraphs (c)(14)(ii) and (iii) or (iv) of this section, as applicable.

(vi) If you determine, through an engineering assessment, that it is technically infeasible to route the pump designated facility emissions to a process or control device, you must retain records of your demonstration and certification that it is technically infeasible as required under § 60.5395c(b)(7).

(vii) If the pump is routed to a process or control device that is subsequently removed from the location or is no longer available such that there is no option to route to a process or control device, you are required to retain records of this change and the records required under paragraph (c)(14)(vi) of this section.

(viii) Records of each change in compliance method, including identification of each natural gas-driven pump which changes its method of compliance, the new method of compliance, and the date of the change in compliance method.

(ix) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(d) *Electronic reporting.* If you are required to submit notifications or reports following the procedure specified in this paragraph (d), 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 (d)(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 in this paragraph (d).

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