TITLE 45
LEGISLATIVE RULE
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY

SERIES 16
STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

§45-16-1. General.

1.1. Scope. -- This rule establishes and adopts standards of performance for new stationary sources promulgated by the United States Environmental Protection Agency pursuant to section 111(b) of the federal Clean Air Act, as amended. This rule codifies general procedures and criteria to implement the standards of performance for new stationary sources set forth in 40 CFR Part 60. The Secretary hereby adopts these standards by reference. The Secretary also adopts associated reference methods, performance specifications and other test methods which are appended to these standards.

1.2. Authority. -- W.Va. Code §22-5-4.

1.3. Filing Date. -- ~~June 16, 2016~~.

1.4. Effective Date. -- ~~July 1, 2016~~.

1.5. Incorporation By Reference. -- Federal Counterpart Regulation. The Secretary has determined that a federal counterpart rule exists, and in accordance with the Secretary's recommendation, with limited exception, this rule incorporates by reference 40 CFR Parts 60 and 65, to the extent referenced in 40 CFR Part 60, effective ~~June 1, 2015~~ June 1, 2016.

~~1.6. Former Rules. -- This legislative rule amends 45CSR16 "Standards of Performance for New Stationary Sources" which was filed April 6, 2015, and became effective June 1, 2015.~~

§45-16-2. Definitions.

2.1. "Administrator" means the Administrator of the United States Environmental Protection Agency or his or her authorized representative.

2.2. "Clean Air Act" ("CAA") means the federal Clean Air Act, found at 42 U.S.C. §7401 et seq.

2.3. "Secretary" means the Secretary of the Department of Environmental Protection or other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§22-1-6 or 22-1-8.

2.4. Other words and phrases used in this rule, unless otherwise indicated, shall have the meaning ascribed to them in 40 CFR Part 60. Words and phrases not defined therein shall have the meaning given to them in the federal Clean Air Act.

§45-16-3. Requirements.

3.1. No person may construct, reconstruct, modify, or operate or cause to be constructed, reconstructed, modified, or operated any source subject to the provisions of 40 CFR Part 60 which results or will result in a violation of this rule.

§45-16-4. Adoption of Standards.

4.1. Standards. -- The Secretary hereby adopts and incorporates by reference the provisions of 40 CFR Parts 60 and 65, to the extent referenced in 40 CFR Part 60, including any reference methods, performance specifications and other test methods which are appended to these standards and contained in 40 CFR Parts 60 and 65, effective ~~June 1, 2015~~ June 1, 2016, for the purposes of implementing a program for standards of performance for new stationary sources, except as follows:

4.1.a. 40 CFR §60.9 is amended to provide that information shall be available to the public in accordance with W.Va. Code §§22-5-1 et seq., 29B-1-1 et seq., and 45CSR31; and

4.1.b. Subparts B, C, Ca, Cb, Cc, Cd, Ce, Ea, Eb, Ec, WWW, AAAA, BBBB, CCCC, DDDD, EEEE, FFFF, LLLL and MMMM of 40 CFR Part 60 shall be excluded.

4.1.c. The following subparts of 40 CFR Part 60 relating to wood-burning heaters and appliances are expressly excluded and are not adopted or incorporated by reference in this rule:

4.1.c.1. The 2015 amendments to subpart AAA; and

4.1.c.2. Subpart QQQQ.

§45-16-5. Secretary.

5.1. Any and all references in 40 CFR Parts 60 and 65 to the “Administrator” are amended to be the “Secretary” except as follows:

5.1.a. Where the federal regulations specifically provide that the Administrator shall retain authority and not transfer authority to the Secretary;

5.1.b. Where provisions occur which refer to:

5.1.b.1. Alternate means of emission limitations;

5.1.b.2. Alternate control technologies;

5.1.b.3. Innovative technology waivers;

5.1.b.4. Alternate test methods;

5.1.b.5. Alternate monitoring methods;

5.1.b.6. Waivers/adjustments to recordkeeping and reporting;

5.1.b.7. Emissions averaging;

5.1.b.8. Applicability determinations; or

5.1.b.9. The authority to require testing under Section 114 of the Clean Air Act, as amended; or

5.1.c. Where the context of the regulation clearly requires otherwise.

§45-16-6. Permits.

6.1. Nothing contained in this adoption by reference shall be construed or inferred to mean that permit requirements in accordance with applicable rules shall be in any way be limited or inapplicable.

§45-16-7. Inconsistency Between Rules.

7.1. In the event of any inconsistency between this rule and any other rule of the ~~West Virginia Department of Environmental Protection~~ Division of Air Quality, the inconsistency shall be resolved by the determination of the Secretary and the determination shall be based upon the application of the more stringent provision, term, condition, method or rule.

Federal Register Notices provided below include:

80 Fed. Reg. 38628, July 7, 2015

81 Fed. Reg. 31515, May 19, 2016

80 Fed. Reg. 64510, October 23, 2015

80 Fed. Reg. 48262, August 12, 2015

80 Fed. Reg. 75178, December 1, 2015

80 Fed. Reg. 50386, August 19, 2015

80 Fed. Reg. 44772, July 27, 2015

80 Fed. Reg. 42397, July 17, 2015

81 Fed. Reg. 20172, April 6, 2016

EPA-APPROVED NON-REGULATORY PROVISIONS AND QUASI-REGULATORY MEASURES IN THE ARKANSAS SIP—Continued

Name of SIP provision	Applicable geographic or nonattainment area	State submittal/ effective date	EPA Approval date	Explanation
* *	*	*	*	* *
Interstate transport for the 1997 ozone NAAQS (Noninterference with measures required to prevent significant deterioration of air quality in any other State).	Statewide	4/5/11	8/20/12 (77 FR 50033).	Approved except as it relates to GHGs. The GHG PSD deficiency was addressed on April 2, 2013 (78 FR 19596).
* *	*	*	*	* *

§ 52.172 [Amended]

■ 3. Section 52.172 is amended by removing paragraph (b) and redesignating paragraphs (c) and (d) as paragraphs (b) and (c), respectively.

■ 4. Section 52.181 is amended by redesignating paragraph (a)(5) as paragraph (a)(7) and adding paragraphs (a)(5) and (6) to read as follows:

§ 52.181 Significant deterioration of air quality.

(a) * * *

(5) November 6, 2012—submittal of Regulation 19, Chapter 9, Prevention of Significant Deterioration which provided the authority to regulate greenhouse gas emissions in the Arkansas PSD program.

(6) January 7, 2014—submittal of Regulation 19, Chapter 9, Prevention of Significant Deterioration which updated the Arkansas PSD program to provide for the issuance of greenhouse gas plantwide applicability limit permits.

* * * * *

[FR Doc. 2015–16388 Filed 7–6–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2013–0696; FRL–9929–25–OAR]

RIN 2060–AR81

Performance Specification 18—Performance Specifications and Test Procedures for Hydrogen Chloride Continuous Emission Monitoring Systems at Stationary Sources

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing performance specifications and test procedures for hydrogen chloride (HCl) continuous emission monitoring systems (CEMS) to provide sources and regulatory agencies with criteria and test procedures for evaluating the acceptability of HCl CEMS. The final performance specification (Performance Specification 18) includes requirements for initial acceptance, including instrument accuracy and stability assessments. This action also finalizes quality assurance (QA) procedures for HCl CEMS used for compliance determination at stationary sources. The QA procedures (Procedure 6) specify the minimum QA requirements necessary for the control and assessment of the quality of CEMS data submitted to the EPA.

This action establishes consistent requirements for ensuring and assessing the quality of HCl data measured by CEMS. The affected systems are those used for determining compliance with emission standards for HCl on a continuous basis as specified in an applicable permit or regulation. The affected industries and their North American Industry Classification System (NAICS) codes are listed in the **SUPPLEMENTARY INFORMATION** section of this preamble.

DATES: This final rule is effective on July 7, 2015.

ADDRESSES: *Docket:* The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2013–0696. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, 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 either electronically through *www.regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Ave. NW., Washington, DC 20004. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Candace Sorrell, Office of Air Quality Planning and Standards, Air Quality Assessment Division (AQAD), Measurement Technology Group, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27709; telephone number: (919) 541–1064; fax number: (919) 541–0516; email address: *sorrell.candace@epa.gov.*

SUPPLEMENTARY INFORMATION: The information in this preamble is organized as follows:

C. Regulatory Flexibility Act (RFA)
D. Unfunded Mandates Reform Act (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act (NTTAA)
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act (CRA)

I. General Information

A. Does this action apply to me?

The major entities that would potentially be affected by the final Performance Specification 18 (PS–18) and the QA requirements of Procedure 6 for gaseous HCl CEMS are those entities that are required to install a new HCl CEMS, relocate an existing HCl CEMS, or replace an existing HCl CEMS under any applicable subpart of 40 CFR parts 60, 61, or 63. Table 1 of this preamble lists the current federal rules by subpart and the corresponding source categories to which the PS–18 and Procedure 6 potentially would apply.

TABLE 1—SOURCE CATEGORIES THAT WOULD POTENTIALLY BE SUBJECT TO PS–18 AND PROCEDURE 6

Subpart(s)	Source category
40 CFR part 63	
Subpart LLL	Portland Cement Manufacturing Industry.
Subpart UUUUU	Coal- and Oil-fired Electric Utility Steam Generating Units.

The requirements of PS–18 and Procedure 6 may also apply to stationary sources located in a state, district, reservation, or territory that adopts PS–18 or Procedure 6 in its implementation plan.

We plan to amend 40 CFR part 63 subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units to offer PS–18 and Procedure 6 as an alternative to Performance Specification 15 (PS–15) for continuous monitoring of HCl. On February 17, 2015 (80 FR 8442), we proposed amendments to appendix B of subpart UUUUU that clarify that PS–18 and Procedure 6 will be allowed and how they are to be implemented under subpart UUUUU. Note, prior to the time that these amendments are finalized, the alternative test method approval process of 40 CFR 63.7(f) is available as a way for affected facilities to request approval to use PS–18/Procedure 6 in lieu of PS–15.

With regard to 40 CFR part 63, subpart LLL, which affects Portland cement manufacturing facilities and includes HCl monitoring requirements, no amendments will be needed as Subpart LLL already allows for use of any promulgated performance specification for HCl CEMS in 40 CFR part 60, appendix B.

Table 2 lists the corresponding NAICS codes for the source categories listed in Table 1 of this preamble.

TABLE 2—NAICS FOR POTENTIALLY REGULATED ENTITIES

Industry	NAICS Codes
Fossil Fuel-Fired Electric Utility Steam Generating Units	[a] 221112 [b] 221122 [c] 921150
Portland Cement Manufacturing Plants	327310

[a] Industry in Indian Country.
[b] Federal, state, local/tribal government owned.
[c] Industry in Indian Country.

Tables 1 and 2 are not intended to be exhaustive, but rather they provide a guide for readers regarding entities potentially affected by this action. If you have any questions regarding the potential applicability of PS–18 and test procedures (Procedure 6) to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

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 action is available on the Internet through the EPA's Technology Transfer Network (TTN) Web site, a forum for information and technology exchange in various areas of air quality management, measurement standards and implementation, etc. Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the promulgation and key technical documents on the TTN Web site: *http://www.epa.gov/ttn/emc/promulgated.html.*

C. Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by September 8, 2015. Under section 307(d)(7)(B) of the CAA, only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements. Section 307(d)(7)(B) also provides a mechanism for us 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. EPA, Room 3000, William Jefferson Clinton 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. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Background

The EPA recently promulgated the Portland Cement Maximum Achievable Control Technology (MACT) rule (75 FR 54970, September 9, 2010; 78 FR 10006, February 12, 2013) and the Mercury and Air Toxics Standards (MATS) rule (77 FR 9303, February 16, 2012; 78 FR 24075, April 24, 2013). Both rules specify the use of extractive Fourier transform infrared spectroscopy (FTIR) and PS–15 when affected facilities opt or are required to continuously measure HCl emissions. To facilitate use of alternative technologies to FTIR and to aid in measuring the low levels of HCl specified in those rules, the EPA has developed and is promulgating these new specifications and quality control (QC) procedures (PS–18 and Procedure 6) for HCl CEMS as an alternative to the use of PS–15.

Multiple technologies are available for HCl emissions monitoring. The goals of PS–18 and Procedure 6 are (1) to allow for the use of different HCl CEMS sampling and analytical technologies as long as the required performance criteria set out in the performance specification (PS) are met; and (2) to establish consistent requirements for ensuring and assessing the quality of data measured by a HCl CEMS.

Performance Specification 18 and Procedure 6 were proposed on May 14, 2014 (79 FR 27690). The initial public comment period was extended (from 30 to 60 days; ending July 13, 2014) in response to commenter requests. We reviewed and considered comments on the proposed PS–18 and Procedure 6 and have made several changes to the specifications and QA procedures finalized with this action to address concerns and improve the proposed performance specifications and procedures.

Under section 553(d) of the Administrative Procedures Act (APA), 5 U.S.C. 553(d), the agency may make a rule immediately effective ''for good cause found and published with the rule.'' For the reasons discussed below, the EPA believes there is ''good cause'' to make this amendment effective upon publication in the **Federal Register**. This rule establishes a new measurement option, and not a new underlying requirement. The sooner the new option is available, more flexibility will be provided to regulated parties.

III. Changes Included in the Final Performance Specification 18 and Procedure 6

This rule finalizes PS–18 and Procedure 6, as proposed, except with five revisions in response to public comments. First, we expanded the options for using dynamic spiking (DS) with extractive systems and clarified the spiking procedures for integrated path systems through the use of ''method of standard additions'' in daily QC checks and as a replacement for the quarterly relative accuracy audit (RAA). Next, we eliminated the requirement for paired or duplicate trains when performing relative accuracy test audits (RATAs) using Method 26A. This change was based on data provided by stakeholders and the EPA's Office of Research and Development, which showed that this reference method (RM) generated data acceptable to allay concerns about the data quality at concentrations near the compliance limit. In response to commenters who claimed that stratification testing is overly burdensome and unwarranted, we revised PS–18 to offer three RM traverse point options that can be used without the need for stratification testing and added clarifying language concerning the stratification testing procedures. We removed calibration range above span requirements in both PS–18 and Procedure 6 because we decided, after considering concerns raised by commenters, that above span compliance requirements are best handled on a rule-specific basis within individual subparts regulating differing industries/categories. The procedures for assuring the quality of the data when an applicable regulation requires measurements above span were not removed. Lastly, we added flexibility to both PS–18 and Procedure 6 in the relative accuracy criteria.

IV. Summary of Major Comments and Responses

A comprehensive summary of the comments received on the proposed PS–18 and procedures (Procedure 6) and our responses to those comments can be found in the Summary of Public Comments and Responses document,[1] which is available in the docket for this action (*see* Docket No. EPA–HQ–OAR–2013–0696). Some of the major comments received on the PS and QA procedures and our responses to those comments are summarized by subject in the following paragraphs.

A. Dynamic Spiking

Under the proposed PS–18, we required DS into the CEMS using a National Institute of Standards and Technology (NIST) traceable standard to demonstrate initial performance at sources with emission levels near the detection limit of the CEMS.

1. Expanded Use of Dynamic Spiking as an Optional QC Check

Several comments received on the proposal recommended that the EPA allow for optional use of DS procedures for all certification and QA procedures as alternatives to using external calibration standards. Commenters opined that a choice between performing DS or daily zero and upscale checks should be available to the manufacturer and CEMS user for all CEMS technologies, and that the regulation should not mandate the use of either technique to exclude particular technologies.

After consideration of comments, we have revised the final PS and QA procedures to allow for optional use of DS procedures for the following:

(1) The upscale (mid-level) portion of the 7-day calibration drift test,

(2) The daily mid-level CD check, and

(3) The quarterly data accuracy assessments.

In addition, if the source meets the criteria of section 5.5 in Procedure 6, we are allowing for a dynamic spiking audit (DSA) as a replacement for the RATA once every 2 years.

A DS procedure does not provide sufficient information to replace the 7-day or daily zero CD check, the initial measurement error (ME) test, or completely replace the relative accuracy (RA) comparison with a RM. The 7-day and daily zero CD checks using exclusively zero gas provide an absolute check of the instrument zero. Should hysteresis be a concern, humidified zero gas may be used.

After consideration, we decided that DS was not a suitable replacement for the 7-day or daily zero CD check. We added an additional procedure for use of a DS as an option for the 7-day and daily mid-level CD checks to section 11.8 of PS–18 and section 4.1 of Procedure 6 in the final rule. The acceptance criteria for use of a DS as a mid-level CD check is the same as that for the classic CD check procedure, ±5 percent of span for a single spike; an equation has been added to appendix A of PS–18 for calculating this value. It is important to note that under the final rule, the 7-day and daily upscale CD checks (whether done using the classic procedure and pure calibration gases or done using a DS procedure) are limited to the use of a mid-level gas. The reason for this limitation is to (1) ensure that the upscale calibration is closer to the measured values, (2) mitigate hysteresis effects, and (3) ensure that the CD values determined using either the classic procedure or a DS procedure are on a consistent basis.

We have retained the requirement for use of pure calibration gases as the only option for the ME test. We retained this requirement because we want (at least) an initial direct assessment of the linearity of the system; we do not believe that the nominal costs associated with hysteresis or gas use are critical concerns for this requirement for a one time test.

Use of a DSA as an option for quarterly data accuracy assessment was included in the proposal for Procedure 6; and section 5.2.3 of Procedure 6 has been revised to include clarifying information on spike levels, number of spikes, and audit calculations.

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[1] U.S. Environmental Protection Agency. *Response to Comments on Proposed Rule: Performance Specification 18—Specifications and Test Procedures for Gaseous HCl Continuous Emission Monitoring Systems at Stationary Sources.* Office of Air Quality Planning and Standards (OAQPS), Air Quality Assessment Division (AQAD), Research Triangle Park, NC; May 2015.

The final rule requires yearly conduct of a RATA involving comparison against a RM unless the optional criteria are met to reduce this requirement to every other year. The RATA provides quantitative assessment of the CEMS as well as confirmation of the continued representativeness of the CEMS sampling location. The DS option confirms the quantitative output of the CEMS comparison but lacks the traversing necessary to evaluate representativeness of the CEMS sampling point.

2. Removal of the Dynamic Spiking Requirement for Low Emission Sources

We received several comments on the proposed specifications requiring a DS verification test whenever the HCl measurements are less than or equal to 20 percent of the applicable standard (in section 11.9.4.3) arguing that the provisions are unnecessary. One commenter asserted that there is no purpose or precedent for requiring alternative or additional QA testing, in addition to a RATA, because a unit is operating well below the applicable standard or the RM quantification limit and that having such a requirement does not appreciably provide any more assurances that the HCl CEMS is operating properly than demonstrated by meeting the RA requirements. One commenter asserted that kilns with very low or no HCl emissions should not be required to conduct extra tests and that DS procedures equivalent to those used in PS–15 DS should be allowed as an alternative to the RA test and not in addition to the RA test to validate installed CEMS.

Upon review of these comments, we have decided that requiring a DS, merely because emissions are low, may present a disincentive to maintaining low emissions without appreciably assuring better operation of HCl CEMS. Therefore, we have revised PS–18 to remove this requirement for low HCl emission sources.

B. Duplicate Trains When Performing RATA

The proposed PS–18 required (1) paired or duplicate trains when performing RATAs using Method 26A as the RM and (2) invalidation of data pairs not meeting specified relative difference criteria (sections 11.9.4.4 and 11.9.4.6).

Several commenters requested that the requirement for paired trains be removed when Method 26A is used as the RM when conducting a RATA. Commenters argued that dual trains will add unnecessary time, more expense, and will complicate the testing process. These commenters generally opined that the additional burdens associated with requiring dual trains will not increase accuracy and will make it more unlikely that facilities will choose to implement HCl CEMS.

Commenters generally expressed that both Method 26 and 26A have been widely used for a number of years to develop data both to set standards and to show compliance, and that Method 26A is very durable, well-designed, and provides accurate/high quality data. One commenter acknowledged that variability is higher as measurements get closer to the detection limit; however, the commenter asserted that this is true for any analytical method, not just Method 26A. Another commenter noted that Method 26A has a known negative bias below 20 ppmv (parts per million by volume); however, this bias would show up in both trains (if a dual train was used) and would not have any impact on determining accuracy.

One commenter reported that PS–12A is the only known PS that requires the use of paired RM sampling trains (*see* PS–12A, section 8.4.2), and requires dual trains when using Method 29. The commenter further reported that paired trains are recommended but not required in PS–11 (*see* section 8.6(1)(i)). The commenter suggested that the EPA adopt an alternative standard in which the EPA would recommend the use of paired trains, but not require them, similar to the requirements of PS–11.

One commenter stated that random uncontrolled events can occur that can affect the results of a RM test, and if such an event occurs during a RATA, the sample may not meet the relative difference (RD) performance criteria and would count as one of a maximum of three exclusions/rejections allowed in the proposed PS–18. This commenter contended that if dual trains are employed, there is twice the probability of a random event occurring that could result in a rejection. One commenter stated that requiring dual trains could result in the discarding of otherwise valid RM runs.

Commenters asserted that if the RM data is of poor quality or there is a large enough error in the reference point, either that data point will have to be discarded (if allowed) or the instrument will not pass the RATA. One commenter opined that facilities should have the choice to use single trains and risk failing the RATA due to suspect RM data.

We acknowledge that requiring duplicate Method 26A trains during RATA tests adds some complexity and cost to initial and ongoing quality demonstration of CEMS performance. Our primary concern is the confidence in RM data at low concentrations. We also acknowledge that the PS–18 proposal only requires duplicate sampling for Method 26A and does not address duplicate Method 320/Method 321 as a requirement during RATA testing. Furthermore, from the data provided by stakeholders and by the EPA's Office of Research and Development (evaluating the use of paired Method 26A trains), we are convinced that Method 26A performs as a prescriptive method to generate data acceptable to allay concerns about the quality of this RM at concentrations at the compliance limits of current MACT rules. We have revised PS–18 to remove the requirement for paired reference Method 26A sampling trains during RATA tests.

C. Stratification Test Requirements

Several commenters opined that stratification testing is overly burdensome and unwarranted.

One commenter opined that the stratification test would be overly burdensome for sources using Method 26A because test results would not be readily available onsite, which would force sources to use instrumental methods (*e.g.,* Method 320) that yield real time HCl data. Another commenter stated that the requirements for a stratification test for HCl are unwarranted because extractive CEM or cross-stack tunable diode laser (TDL) instruments are only effective in measuring HCl in the vapor phase, and stratification only occurs with non-vapor droplets and higher-mass aerosols. The commenter asserted that gas phase measurements have always been associated with a homogeneous mixture of molecules across a stack or duct under turbulent flow conditions, which is always the case at plants with HCl emission streams. The commenter asserted that other reasons why a stratification test is not warranted include (1) the fact that other extractive HCl RMs, including Methods 320, 321, and ASTM D6348–12, do not require a stratification test, and (2) if stratification exists and is statistically significant, the error would be revealed by the RA test.

One commenter asserted that there may be units that would be subject to PS–18 under subpart UUUUU and other rules (*e.g.,* 40 CFR part 75) that have already performed stratification testing at their RM sampling location. The commenter suggested that to avoid unnecessary repetitive stratification testing, the EPA include an exemption from the stratification testing requirement for RM locations that have been previously evaluated.

Another commenter stated that the proposed stratification test procedures and acceptance criteria specified in section 11.9.3 of the proposal (1) are unnecessary for most sources and do not need to be performed, (2) contain confusing references to the CEMS and RM sampling points, (3) provide inappropriate acceptance criteria, and (4) are not supported by any data.

One commenter suggested that the stratification test sections be revised to (1) eliminate the test when the monitor and RA test locations are downstream of induced draft (ID) fan or other well mixed location, (2) eliminate the test for sources that have no measurable HCl during mill on operation, (3) explicitly state stratification tests should not be done during transient conditions including mill off operation, (4) specify that only an oxygen (O_2) traverse is necessary if the only potential source of stratification is air in-leakage, (5) specify a stratification test, when necessary, be done at the RA test location and not the CEMS location, if different, and (6) specify that level of detection (LOD) criteria for allowing the alternative sulfur dioxide (SO_2), carbon dioxide (CO_2), and carbon monoxide (CO) tests are based on the RM LOD and not the CEMS LOD.

One commenter also suggested that, unless the EPA can demonstrate that HCl stratification is an actual issue, the EPA should revise PS–18 to incorporate the identical requirements in PS–2, section 8.13.2, that requires sampling three points on a line, and require stratification tests only where there is a reason to expect stratification actually exists. The commenter also asserted that there is no need to acquire and use a series of EPA Protocol SO_2 calibration gases and comprehensive series of procedures intended for test runs.

We disagree with the commenters that stratification testing is unnecessary and overly burdensome. Contrary to the assertions of some commenters that stratification testing is not necessary, gaseous pollutants can be stratified. While turbulent flow and other conditions may eliminate stratification under certain conditions, the EPA does not agree that those conditions can be easily defined nor that if stratification exists, it would always be revealed by the RA test. It is the EPA's position that to ensure collection of representative RM samples, it is necessary to confirm the absence of stratification before allowing single point or 3-point sampling that does not include the centroid of the duct.

However, we do recognize that there is a need to provide one or more options for RM sample point selection that do not require stratification testing and we also understand that the proposed language of section 11.9.3 may have caused some confusion. Therefore, we have revised PS–18 to offer three RM traverse point options that can be used without the need for stratification testing. These options are a 3-point traverse (commonly known as the a ''3-point long line'') that includes the centroid of the duct, a 6-point traverse as allowed under 40 CFR part 75, or a 12-point traverse, as was requested by one commenter. Testers desiring to test at a single point or at three points within two meters of a single port (commonly known as a ''3-point short line'') will need to conduct stratification testing to demonstrate the absence of stratification or only minimal stratification, respectively.

Additionally, after consideration of comments received on stratification testing, we have also revised the final PS–18 to:

(1) Clarify that the purpose of stratification testing is only for selection of RM sampling points;

(2) Simplify the use of SO_2 as a surrogate for stratification testing without restriction to offer a simpler option when using Method 26A as the RM;

(3) Clarify (as commenters have recommended) that stratification testing must be conducted at the same location as the RM testing; and

(4) Clarify that stratification testing should not be conducted during transient conditions.

D. Calibration Range Above Span

Commenters expressed concern over the proposed requirements related to calibration range above span or CRAS (defined as the upper limit of the measurement range based on a conservatively high estimate of the range of HCl measurements expected from the source category). Specifically, commenters expressed concern that the proposed CRAS requirements:

(1) Conflict with the definition of ''span'' in both 40 CFR part 60, subpart UUUUU (subpart UUUUU), appendix A, and in 40 CFR part 75 (section 72.2).

(2) Conflict with the recently promulgated 40 CFR part 63, subpart LLL (subpart LLL) requirements.

(3) Would likely create one hour of unnecessary CEMS data loss each time it is performed in view of the time required for the CEMS to achieve and stabilize at the high concentration level and subsequently recover to the normal operating level.

(4) Require that the HCl CEMS be adjusted when the calibration drift exceeds 0.5 ppm (parts per million) at the zero or at 15–20 ppm levels. Commenters stated that upscale or CRAS levels would impose arbitrary adjustments simply chasing noise and that it should be changed to a requirement to inspect the CEMS and determine the proper corrective action.

Commenters stated that the span and range of a CEMS depend on the type of technology used and that the EPA references the mercury CEMS as the precedent for the above span requirement. Commenters asserted that this can be problematic because, whereas mercury CEMSs have a linear response, other technologies may not have a linear response.

After considering concerns raised by commenters, we decided that above span calibration requirements are best handled on a rule-specific basis within individual subparts regulating differing industries/categories. Therefore, we revised PS–18 and Procedure 6 to remove calibration range above span requirements and made them an option in Procedure 6. Subpart LLL-specific above span calibration technical revisions have been made under that rulemaking (*see* 79 FR 68821; November 19, 2014).

E. RATA Acceptance Criteria for Low Concentration Sources

The proposed PS–18 section 5.3.5 referenced an alternative criterion for RA that would apply in instances where the emission level for the test is less than 50 percent of the applicable standard. The proposed alternative criterion was for when the RM result is less than 50 percent of the emission standard and the emission standard is used in the denominator of the equation for calculating RA to be less than or equal to 15 percent. We received comments that asserted that this requirement is inconsistent with other alternative RA options used in other performance specifications. Some commenters supported the use of an absolute value; *i.e.,* plus or minus 1 ppm if the RM is less than 3 ppm, which they reported would be similar to the requirements for mercury CEMS under subpart UUUUU.

We recognize that calibration standards and measurement technology exist to demonstrate the quality of HCl emission measurements at or above 1 ppm and that existing CEMS measurement technology can meet PS–18 RA requirements (*see* Docket Nos. EPA–HQ–OAR–2013–0696–0030 and 0031). For HCl emission limits equal to or less than 1 ppm, RA is measured nearer the quantitation limit of current instrument technology, and an alternative RA acceptance criterion similar to that in PS–2 of 40 CFR part 60, appendix B may be applicable. Therefore, we have revised the alternative criterion for RA in section 13.4 of PS–18 to allow, where the average RM level during the test is less than 75 percent of the applicable emission limit, substitution of the equivalent emission limit in parts per million by volume wet (ppmvw) in the denominator of the equation for calculating RA. Note that this revision applies to both PS–18 and section 6 of Procedure 6.

V. Statutory and Executive Order Reviews

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

This action is not a significant regulatory action and was, therefore, not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose an information collection burden under the PRA. This action provides performance criteria and QA test procedures for assessing the acceptability of HCl CEMS performance and data quality. These criteria and QA test procedures do not add information collection requirements beyond those currently required under the applicable regulation.

C. 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. This action will not impose any requirements on small entities. This action provides facilities with an alternative to PS–15 and FTIRs for measuring HCl which is currently required in several rules.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local or tribal governments or the private sector.

E. 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.

F. 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 finalizes performance specifications that can be used as an additional option to PS–15 for HCl continuous emissions monitoring. Thus, Executive Order 13175 does not apply to this action.

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

The EPA interprets Executive Order 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 Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

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

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. This action will help to ensure that emission control devices are operated properly and maintained as needed, thereby helping to ensure compliance with emission standards, which would benefit all affected populations.

K. Congressional Review Act (CRA)

This action is subject to the 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 procedure, Air pollution control, Continuous emission monitoring systems, Hydrogen chloride, Performance specifications, Test methods and procedures.

Dated: June 25, 2015.

Gina McCarthy,

Administrator.

Part 60, chapter I, title 40 of the Code of Federal Regulations is amended 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. 7401–7601.

■ 2. Appendix B to part 60 is amended by adding Performance Specification 18 to read as follows:

Appendix B to Part 60—Performance Specifications

* * * * *

Performance Specification 18—Performance Specifications and Test Procedures for Gaseous Hydrogen Chloride (HCl) Continuous Emission Monitoring Systems at Stationary Sources

1.0 Scope and Application

1.1 Analyte. This performance specification (PS) is applicable for measuring gaseous concentrations of hydrogen chloride (HCl), CAS: 7647–01–0, on a continuous basis in the units of the applicable standard or in units that can be converted to units of the applicable standard(s).

1.2 Applicability.

1.2.1 This specification is used to evaluate the acceptability of HCl continuous emission monitoring systems (CEMS) at the time of installation or soon after and whenever specified in the regulations. The specification includes requirements for initial acceptance including instrument accuracy and stability assessments and use of audit samples if they are available.

1.2.2 The Administrator may require the operator, under section 114 of the Clean Air Act, to conduct CEMS performance evaluations at other times besides the initial test to evaluate the CEMS performance. See 40 CFR part 60, §§ 60.13(c) and 63.8(e)(1).

1.2.3 A source that demonstrates their CEMS meets the criteria of this PS may use the system to continuously monitor gaseous HCl under any regulation or permit that requires compliance with this PS. If your CEMS is capable of reporting the HCl concentration in the units of the applicable standard, no additional CEMS components are necessary. If your CEMS does not report concentrations in the units of the existing standard, then other CEMS components (*e.g.,* oxygen (O_2), temperature, stack gas flow, moisture and pressure) may be necessary to convert the units reported by your CEMS to the units of the standard.

1.2.4 These specification test results are intended to be valid for the life of the system. As a result, the HCl measurement system must be tested and operated in a configuration consistent with the configuration that will be used for ongoing continuous emissions monitoring.

1.2.5 Substantive changes to the system configuration require retesting according to this PS. Examples of such conditions include, but are not limited to: major changes in dilution ratio (for dilution based systems); changes in sample conditioning and transport, if used, such as filtering device design or materials; changes in probe design or configuration and changes in materials of construction. Changes consistent with instrument manufacturer upgrade that fall under manufacturer's certification do not require additional field verification. Manufacturer's upgrades require recertification by the manufacturer for those requirements allowed by this PS, including interference, level of detection (LOD), and light intensity qualification.

1.2.6 This specification is not designed to evaluate the ongoing CEMS performance nor does it identify specific calibration techniques and auxiliary procedures to assess CEMS performance over an extended period of time. The requirements in appendix F, Procedure 6 are designed to provide a way to assess CEMS performance over an extended period of time. The source owner or operator is responsible to calibrate, maintain, and operate the CEMS properly.

2.0 Summary of Performance Specification

2.1 This specification covers the procedures that each CEMS must meet during the performance evaluation test. Installation and measurement location specifications, data reduction procedures, and performance criteria are included.

2.2 The technology used to measure gaseous HCl must provide a distinct response and address any appropriate interference correction(s). It must accurately measure gaseous HCl in a representative sample (path or point sampling) of stack effluent.

2.3 The relative accuracy (RA) must be established against a reference method (RM) (*i.e.,* Method 26A, Method 320, ASTM International (ASTM) D6348–12, including mandatory annexes, or Method 321, as appropriate for the source concentration and category). Method 26 may be approved as a RM by the Administrator on a case-by-case basis if not otherwise allowed or denied in an applicable subpart of the regulations.

2.4 A standard addition (SA) procedure using a reference standard is included in appendix A to this performance specification for use in verifying LOD. For extractive CEMS, where the SA is done by dynamic spiking (DS), the appendix A procedure is allowed as an option for assessing calibration drift and is also referenced by Procedure 6 of appendix F to this part for ongoing quality control tests.

3.0 Definitions

3.1 *Calibration Cell* means a gas containment cell used with cross stack or integrated path (IP) CEMS for calibration and to perform many of the test procedures required by this performance specification. The cell may be a removable sealed cell or an evacuated and/or purged cell capable of exchanging reference and other calibration gases as well as zero gas standards. When charged, it contains a known concentration of HCl and/or interference gases. The calibration cell is filled with zero gas or removed from the optical path during stack gas measurement.

3.2 *Calibration Drift* (CD) means the absolute value of the difference between the CEMS output response and an upscale reference gas or a zero-level gas, expressed as a percentage of the span value, when the CEMS is challenged after a stated period of operation during which no unscheduled adjustments, maintenance or repairs took place.

3.3 *Centroidal Area* means a central area that is geometrically similar to the stack or duct cross section and is no greater than 10 percent of the stack or duct cross-sectional area.

3.4 *Continuous Emission Monitoring System* (CEMS) means the total equipment required to measure the pollutant concentration or emission rate continuously. The system generally consists of the following three major subsystems:

3.4.1 Sample Interface means that portion of the CEMS used for one or more of the following: sample acquisition, sample transport, sample conditioning, defining the optical measurement path, and protection of the monitor from the effects of the stack effluent.

3.4.2 HCl Analyzer means that portion of the HCl CEMS that measures the total vapor phase HCl concentration and generates a proportional output.

3.4.3 Data Recorder means that portion of the CEMS that provides a permanent electronic record of the analyzer output. The data recorder may record other pertinent data such as effluent flow rates, various instrument temperatures or abnormal CEMS operation. The data recorder may also include automatic data reduction capabilities and CEMS control capabilities.

3.5 *Diluent Gas* means a major gaseous constituent in a gaseous pollutant mixture. For combustion sources, either carbon dioxide (CO2) or oxygen (O2) or a combination of these two gases are the major gaseous diluents of interest.

3.6 *Dynamic Spiking* (DS) means the procedure where a known concentration of HCl gas is injected into the probe sample gas stream for extractive CEMS at a known flow rate to assess the performance of the measurement system in the presence of potential interference from the flue gas sample matrix.

3.7 *Independent Measurement(s)* means the series of CEMS data values taken during sample gas analysis separated by two times the procedure specific response time (RT) of the CEMS.

3.8 *Integrated Path CEMS* (IP–CEMS) means an in-situ CEMS that measures the gas concentration along an optical path in the stack or duct cross section.

3.9 *Interference* means a compound or material in the sample matrix other than HCl whose characteristics may bias the CEMS measurement (positively or negatively). The interference may not prevent the sample measurement, but could increase the analytical uncertainty in the measured HCl concentration through reaction with HCl or by changing the electronic signal generated during HCl measurement.

3.10 *Interference Test* means the test to detect CEMS responses to interferences that are not adequately accounted for in the calibration procedure and may cause measurement bias.

3.11 *Level of Detection* (LOD) means the lowest level of pollutant that the CEMS can detect in the presence of the source gas matrix interferents with 99 percent confidence.

3.12 *Liquid Evaporative Standard* means a reference gas produced by vaporizing National Institute of Standards and Technology (NIST) traceable liquid standards of known HCl concentration and quantitatively diluting the resultant vapor with a carrier gas.

3.13 *Measurement Error* (ME) is the mean difference between the concentration measured by the CEMS and the known concentration of a reference gas standard, divided by the span, when the entire CEMS, including the sampling interface, is challenged.

3.14 *Optical Path* means the route light travels from the light source to the receiver used to make sample measurements.

3.15 *Path Length* means, for an extractive optical CEMS, the distance in meters of the optical path within a gas measurement cell. For an IP–CEMS, path length means the distance in meters of the optical path that passes through the source gas in the stack or duct.

3.16 *Point CEMS* means a CEMS that measures the source gas concentration, either at a single point at the sampling probe tip or over a path length for IP–CEMS less than 10 percent of the equivalent diameter of the stack or duct cross section.

3.17 *Stack Pressure Measurement Device* means a NIST-traceable gauge or monitor that measures absolute pressure and conforms to the design requirements of ASME B40.100–2010, ''Pressure Gauges and Gauge Attachments'' (incorporated by reference—see § 60.17).

3.18 *Reference Gas Standard* means a NIST-traceable gas standard containing a known concentration of HCl certified in accordance with an EPA traceability protocol in section 7.1 of this PS.

3.19 *Relative Accuracy* (RA) means the absolute mean difference between the gas concentration or the emission rate determined by the CEMS and the value determined by the RM, plus the confidence coefficient of a series of nine test runs, divided by the average of the RM or the applicable emission standard.

3.20 *Response Time* (RT) means the time it takes for the measurement system, while operating normally at its target sample flow rate, dilution ratio, or data collection rate to respond to a known step change in gas concentration, either from a low- or zero-level to a high-level gas concentration or from a high-level to a low or zero-level gas concentration, and to read 95 percent of the change to the stable instrument response. There may be several response times (RTs) for an instrument related to different functions or procedures (*e.g.,* DS, LOD, and ME).

3.21 *Span Value* means an HCl concentration approximately equal to two times the concentration equivalent to the emission standard unless otherwise specified in the applicable regulation, permit or other requirement. Unless otherwise specified, the span may be rounded up to the nearest multiple of 5.

3.22 *Standard Addition* means the addition of known amounts of HCl gas (either statically or dynamically) to the actual measurement path or measured sample gas stream.

3.23 *Zero gas* means a gas or liquid with an HCl concentration that is below the LOD of the measurement system.

4.0 Interferences

Sample gas interferences will vary depending on the instrument or technology used to make the measurement. Interferences must be evaluated through the interference test in this PS. Several compounds including carbon dioxide (CO_2), carbon monoxide (CO), formaldehyde (CH_2O), methane (CH_4), and water (H_2O) are potential optical interferences with certain types of HCl monitoring technology. Ammonia is a potential chemical interference with HCl.

5.0 Safety

The procedures required under this PS may involve hazardous materials, operations, and equipment. This PS may not address all of the safety issues associated with these procedures. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performing these procedures. The CEMS user's manual and materials recommended by the RM should be consulted for specific precautions to be taken.

6.0 Equipment and Supplies

Equipment and supplies for CEMS will vary depending on the measurement technology and equipment vendors. This section provides a description of the equipment and supplies typically found in one or more types of CEMS.

6.1 Sample Extraction System. The portion of an extractive CEMS that collects and transports the sample to the pressure regulation and sample conditioning module. The extraction system must deliver a representative sample to the measurement instrument. The sample extraction system typically consists of a sample probe and a heated umbilical line.

6.2 Sample Conditioning Module. The portion of an extractive CEMS that removes particulate matter and moisture from the gas stream and provides a sample gas stream to the CEMS analysis module or analyzer. You must keep the particle-free gas sample above the dew point temperature of its components.

6.3 HClAnalyzer. The portion of the CEMS that detects, quantifies and generates an output proportional to the sample gas HCl concentration.

6.4 System Controller. The portion of the CEMS that provides control of the analyzer and other sub-systems (*e.g.,* sample extraction, sample conditioning, reference gas) as necessary for continuous operation and periodic maintenance/QC activities.

6.5 Data Recorder. The portion of the CEMS that provides a record of analyzer output. The data recorder may record other pertinent data such as effluent flow rates, various instrument temperatures or abnormal CEMS operation. The data recorder output range must include the full range of expected HCl concentration values in the gas stream to be sampled including zero and span value.

6.6 Reference Gas System(s). Gas handling system(s) needed to introduce reference and other gases into the measurement system. For extractive CEMS, the system must be able to introduce gas flow sufficient to flood the sampling probe and prevent entry of gas from the effluent stream. For IP–CEMS, the system must be able to introduce a known concentration of HCl, at known cell length, pressure and temperature, into the optical path used to measure HCl gas concentration.

6.7 Moisture Measurement System. If correction of the measured HCl emissions for moisture is required, you must install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases. The following continuous moisture monitoring systems are acceptable: An FTIR system validated according to Method 301 or section 13.0 of Method 320 in appendix A to part 63 of this chapter; a continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O_2 both on a wet basis and on a dry basis; a stack temperature sensor and a moisture look-up table, *i.e.,* a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only); or other continuous moisture measurement methods approved by the Administrator. Alternatively, for any type of fuel, you may determine an appropriate site-specific default moisture value (or values), using measurements made with Method 4—Determination of Moisture Content In Stack Gases, in appendix A–3 to of this part. If this option is selected, the site-specific moisture default value(s) must represent the fuel(s) or fuel blends that are combusted in the unit during normal, stable operation, and must account for any distinct difference(s) in the stack gas moisture content associated with different process operating conditions. At least nine Method 4 runs are required for determining each site-specific default moisture percentage. Calculate each site-specific default moisture value by taking the arithmetic average of the Method 4 runs. Each site-specific moisture default value shall be updated whenever the current value is non-representative, due to changes in unit or process operation, but in any event no less frequently than annually.

7.0 Reagents and Standards

7.1 Reference Gases. Reference gases (*e.g.,* cylinder gases or liquid evaporative standards) used to meet the requirements of this PS must be NIST certified or NIST-traceable and vendor certified to ±5.0 percent accuracy. HCl cylinder gases must be certified according to Reference 5 in section 16 of this PS through a documented unbroken chain of comparisons each contributing to the reported uncertainty. Liquid evaporative standards must be certified using the gravimetrically-based procedures of the latest version of the EPA Traceability Protocol for Qualification and Certification of Evaporative HCl Gas Standards and Humidification of HCl Gas Standards from Cylinders (*see* EPA–HQ–OAR–2013–0696–0026.pdf).

7.2 Cylinder gas and/or liquid evaporative standards must be used within their certification periods.

7.3 High concentration cylinder gas or liquid evaporative HCl standards may be diluted for use in this specification. You must document the quantitative introduction of HCl standards into the system using Method 205, found in 40 CFR part 51, appendix M, or other procedure approved by the Administrator.

8.0 CEMS Measurement Location Specifications and Pretest Preparation

8.1 Prior to the start of your initial PS tests, you must ensure that the CEMS is installed according to the manufacturer's specifications and the requirements in this section. You may use either point or IP sampling technology.

8.2 CEMS Installation. Install the CEMS at an accessible location where the pollutant concentration or emission rate measurements are directly representative of the HCl emissions or can be corrected so as to be representative of the total emissions from the affected facility. The CEMS need not be installed at the same location as the relative accuracy test location. If you fail the RA requirements in this specification due to the CEMS measurement location and a satisfactory correction technique cannot be established, the Administrator may require the CEMS to be relocated.

8.2.1 Single point sample gas extraction should be (1) no less than 1.0 m (3.3 ft.) from the stack or duct wall or (2) within the centroidal area of the stack or duct cross section.

8.2.2 IP–CEMS measurements should (1) be conducted totally within the inner area bounded by a line 1.0 m (3.3 ft.) from the stack or duct wall, (2) have at least 70 percent of the path within the inner 50 percent of the stack or duct cross-sectional area, or (3) be located over any part of the centroidal area.

8.2.2.1 You must measure the IP–CEMS path length from the inner flange of the sampling ports or the inner end of the instrument insertion into the stack cavity using a laser tape measure, mechanical measurement tape, or similar device accurate to ±1.5 mm (0.059 in).

8.2.2.2 You must ensure that any purge flow used to protect IP–CEMS instrument windows from stack gas does not alter the measurement path length. Purge flow of less than or equal to 10 percent of the gas velocity in the duct meets this requirement.

8.2.3 CEMS and Data Recorder Scale Check. After CEMS installation, record and document the measurement range of the HCl CEMS. The CEMS operating range and the range of the data recording device must encompass all potential and expected HCl concentrations, including the concentration equivalent to the applicable emission limit and the span value.

9.0 Quality Control [Reserved]

10.0 Calibration and Standardization [Reserved]

11.0 Performance Specification Test Procedure

After completing the CEMS installation, setup and calibration, you must complete the PS test procedures in this section. You must perform the following procedures and meet the performance requirements for the initial demonstration of your CEMS:

a. Interference Test;
b. Beam Intensity Test (IP–CEMS only);
c. Temperature Verification Procedure (IP–CEMS only);
d. Pressure Verification Procedure (IP–CEMS only);
e. Level of Detection Determination;
f. Response Time Test;
g. Measurement Error Test;
h. Calibration Drift Test; and
i. Relative Accuracy Test.

11.1 Interference Test

11.1.1 Prior to its initial use in the field, you must demonstrate that your monitoring system meets the performance requirements of the interference test in section 13.5 to verify that the candidate system measures HCl accurately in the presence of common interferences in emission matrices.

11.1.2 Your interference test must be conducted in a controlled environment. The equipment you test for interference must include the combination of the analyzer, related analysis software, and any sample conditioning equipment (*e.g.,* dilution module, moisture removal equipment or other interferent scrubber) used to control interferents.

11.1.3 If you own multiple measurement systems with components of the same make and model numbers, you need only perform this interference test on one analyzer and associated interference conditioning equipment combination. You may also rely on an interference test conducted by the manufacturer or a continuous measurement system integrator on a system having components of the same make and model(s) of the system that you use.

11.1.4 Perform the interference check using an HCl reference gas concentration of approximately five times the LOD.

11.1.5 Introduce the interference test gases listed in Table 1 in section 17.0 of this PS to the analyzer/conditioning system separately or in any combination. The interference test gases need not be of reference gas quality.

11.1.5.1 For extractive CEMS, the interference test gases may be introduced directly into the inlet to the analyzer/conditioning system after the probe extension coupling.

11.1.5.2 For IP–CEMS, the interference test gases may be added with the HCl in a calibration cell or separately in a temperature-controlled cell. The effective concentration of the gas in the cell must meet the requirements in Table 1 corrected for absolute pressure, temperature and the nominal stack sampling path length of the CEMS.

11.1.6 The interference test must be performed by combining an HCl reference gas with each interference test gas (or gas mixture). You must measure the baseline HCl response, followed by the response after adding the interference test gas(es) while maintaining a constant HCl concentration. You must perform each interference gas injection and evaluation in triplicate.

Note: The baseline HCl gas may include interference gases at concentrations typical of ambient air (*e.g.,* 21 percent O_2, 400 parts per million (ppm) CO_2, 2 percent H_2O), but these concentrations must be brought to the concentrations listed in Table 1 when their interference effects are being evaluated.

11.1.7 You should document the gas volume/rate, temperature, and pressure used to conduct the interference test. A gas blending system or manifold may be used.

11.1.8 Ensure the duration of each interference test is sufficient to condition the HCl measurement system surfaces before a stable measurement is obtained.

11.1.9 Measure the HCl response of the analyzer/sample conditioning system combination to the test gases in ppmv. Record the responses and determine the overall interference response using Table 2 in section 17.0.

11.1.10 For each interference gas (or mixture), calculate the mean difference (ΔMC_{avg}) between the measurement system responses with and without the interference test gas(es) using Equation 1 in section 12.2. Summarize the results following the format contained in Table 2 in section 17.

11.1.11 Calculate the percent interference (I) for the gas runs using Equation 2 in section 12.2.

11.1.12 The total interference response (*i.e.,* the sum of the interference responses of all tested gaseous components) must not exceed the criteria set forth in section 13.5 of this PS.

11.2 Beam Intensity Test for IP–CEMS

11.2.1 For IP–CEMS, you must establish the tolerance of your system to beam intensity attenuation.

11.2.1.1 Your beam intensity test may be conducted in either a controlled environment or on-site during initial setup and demonstration of your CEMS.

11.2.1.2 If you have multiple measurement systems with components of the same make and model numbers, you need only perform this attenuation check on one system and you may also rely on an attenuation test conducted by the manufacturer on a system having components of the same make and model(s) of the system that you use.

11.2.2 Insert one or more neutral density filter(s) or otherwise attenuate the beam intensity by a known percentage (*e.g.,* 90 percent of the beam intensity).

11.2.3 Perform a high-level HCl reference gas measurement.

11.2.4 Record and report the attenuated beam intensity, the measured HCl calibration gas concentration at full beam intensity, the measured HCl gas concentration with attenuated beam intensity, and the percent difference between the two HCl measurements with and without attenuation of the beam intensity. The percent difference must not exceed the criteria set forth in section 13.6 of this PS.

11.2.5 In the future, you may not operate your IP–CEMS at a beam intensity lower than that established based on the attenuation used during this test. However, you may repeat the test to establish a lower beam intensity limit or level.

11.3 Temperature Measurement Verification Procedure for IP–CEMS

11.3.1 Any measurement instrument or device that is used as a reference in verification of temperature measurement must have an accuracy that is traceable to NIST.

11.3.2 You must verify the temperature sensor used in IP–CEMS measurements on-site as part of the initial installation and verification procedures.

11.3.3 Comparison to Calibrated Temperature Measurement Device.

11.3.3.1 Place the sensor of a calibrated temperature reference device adjacent to the sensor used to measure stack temperature for your IP–CEMS. The calibrated temperature reference device must satisfy the accuracy requirements specified in Table 3 of this PS. The calibrated temperature reference device must also have a range equal to or greater than the range of your IP–CEMS temperature sensor.

11.3.3.2 Allow sufficient time for the response of the calibrated temperature reference device to reach equilibrium. With the process and control device operating under normal conditions, concurrently record the temperatures measured by your IP–CEMS system (M_t) and the calibrated temperature reference device (V_t). You must meet the accuracy requirements specified in section 13.7 of this PS.

11.3.3.3 If your IP–CEMS temperature sensor does not satisfy the accuracy requirement of this PS, check all system components and take any corrective action that is necessary to achieve the required minimum accuracy. Repeat this verification procedure until the accuracy requirement of this specification is satisfied.

11.4 Pressure Measurement Verification Procedure for IP–CEMS

11.4.1 For stack pressure measurement verification, you must select a NIST-traceable gauge or monitor that conforms to the design requirements of ASME B40.100–2010, ''Pressure Gauges and Gauge Attachments,'' (incorporated by reference—see § 60.17) as a reference device.

11.4.2 As an alternative for a calibrated pressure reference device with NIST-traceable accuracy, you may use a water-in-glass U-tube manometer to verify your IP–

CEMS pressure measurement equipment, provided there is also an accurate measurement of absolute atmospheric pressure at the manometer location.

11.4.3 Allow sufficient time for the response of the reference pressure measurement device to reach equilibrium. With the process and control device operating under normal conditions, concurrently record the pressures measured by your IP–CEMS system (M_P) and the pressure reference device (V_p). You must meet the accuracy requirements specified in section 13.8 of this PS.

11.4.4 If your IP–CEMS pressure sensor does not satisfy the accuracy requirement of this PS, check all system components and take any corrective action that is necessary to achieve the required minimum accuracy. Repeat this verification procedure until the accuracy requirement of this specification is satisfied.

11.5 Level of Detection Determination

11.5.1 You must determine the minimum amount of HCl that can be detected above the background in a representative gas matrix.

11.5.2 You must perform the LOD determination in a controlled environment such as a laboratory or manufacturer's facility.

11.5.3 You must add interference gases listed in Table 1 of this PS to a constant concentration of HCl reference gas.

11.5.3.1 You may not use an effective reference HCl gas concentration greater than five times the estimated instrument LOD.

11.5.3.2 For extractive CEMS, inject the HCl and interferents described in section 11.1.5 directly into the inlet to the analyzer.

11.5.3.3 For IP–CEMS, the HCl and interference test gases may be added to a calibration cell or separately in a temperature-controlled cell that is part of the measurement path. The effective concentration of the gas in the cell must meet the requirements in Table 1 corrected for absolute pressure, temperature and the nominal stack sampling path length of the CEMS.

11.5.4 Collect seven or more consecutive measurements separated by twice the RT (described in section 11.6) to determine the LOD.

11.5.5 Calculate the standard deviation of the measured values and define the LOD as three times the standard deviation of these measurements.

11.5.5.1 The LOD for extractive units must be determined and reported in ppmv.

11.5.5.2 The LOD for IP units must be determined and reported on a ppm-meter basis and the site- or installation-specific LOD must be calculated based on the actual measurement path length and gas density of the emissions at the specific site installation in ppmv.

11.5.6 You must verify the controlled environment LOD of section 11.5.2 of this PS for your CEMS during initial setup and field certification testing. You must use the SA procedure in appendix A of this PS with the following exceptions:

11.5.6.1 For the LOD verification in the field, you must make three independent SA measurements spiking the native source concentration by no more than three times the controlled environment LOD concentration determined in section 11.5.5.

11.5.6.2 For extractive CEMS, you must perform the SA as a dynamic spike by passing the spiked source gas sample through all filters, scrubbers, conditioners and other monitoring system components used during normal sampling, and as much of the sampling probe as practical. For IP–CEMS, you must perform the SA procedure by adding or passing a known concentration reference gas into a calibration cell in the optical path of the CEMS; you must also include the source measurement optical path while performing the SA measurement.

11.5.6.3 The amount detected, or standard addition response (SAR), is based on the average difference of the native HCl concentration in the stack or duct relative to the native stack concentration plus the SA. You must be able to detect the effective spike addition (ESA) above the native HCl present in the stack gas matrix. For extractive CEMS, the ESA is calculated using Equation A7 in appendix A of this PS. For IP–CEMS, the ESA is calculated as $C_{i,eff}$ using Equation 4 of this PS.

11.5.6.4 For extractive CEMS, calculate the SAR using Equation A4 in appendix A of this PS. For IP–CEMS, calculate the SAR using Equation A8.

11.5.6.5 If your system LOD field verification does not demonstrate a SAR greater than or equal to your initial controlled environment LOD, you must increase the SA concentration incrementally and repeat the field verification procedure until the SAR is equal to or greater than LOD. The site-specific standard addition detection level (SADL) is equal to the standard addition needed to achieve the acceptable SAR, and SADL replaces the controlled environment LOD. For extractive CEMS, the SADL is calculated as the ESA using Equation A7 in appendix A of this PS. For IP–CEMS, the SADL is the SA calculated using Equation A8 in appendix A of this PS. As described in section 13.1 of this PS, the SADL must be less than 20 percent of the applicable emission limit.

11.6 Response Time Determination. You must determine ME-, LOD- and SA–RT

11.6.1 For ME- or LOD–RT, start the upscale RT determination by injecting zero gas into the measurement system as required by the procedures in section 11.7 or 11.5, respectively. You may use humidified zero gas. For standard addition RT, start the upscale RT determination by measuring the native stack gas concentration of HCl.

11.6.1.1 For extractive CEMS measuring ME- or LOD–RT, the output has stabilized when there is no change greater than 1.0 percent of full scale for 30 seconds.

11.6.1.2 For standard addition RT that includes the stack gas matrix the final stable response may continue to vary by more than 1 percent, but may be considered stable if the variability is random and not continuously rising or falling.

11.6.2 When the CEMS output has stabilized, record the response in ppmv and introduce an upscale (high level) or spike reference gas as required by the relevant procedure.

11.6.3 Record the time (upscale RT) required to reach 95 percent of the change to the final stable value.

11.6.4 Next, for ME or LOD RT, reintroduce the zero gas and record the time required to reach 95 percent of the change to the stable instrument response at the zero gas reading. For SA RT, introduce zero gas to the IP–CEMS cell or stop the spike gas flow to the extractive CEMS as required by the specified procedure and record the time required to reach 95 percent of the change to the stable instrument response of the native gas reading. This time is the downscale RT.

(**Note:** For CEMS that perform a series of operations (purge, blow back, sample integration, analyze, etc.), you must start adding reference or zero gas immediately after these procedures are complete.)

11.6.5 Repeat the entire procedure until you have three sets of data, then determine the mean upscale and mean downscale RTs for each relevant procedure. Report the greater of the average upscale or average downscale RTs as the RT for the system.

11.7 Measurement Error (ME) Test

11.7.1 On the same day and as close in time as practicable to when the ME test is conducted, perform and meet requirements for a calibration drift (CD) test using a zero gas as used in the Seven-Day Drift Test (see section 11.8) and document and report the results. To meet this requirement, the ME test may be conducted during the Seven-Day CD Test.

11.7.2 Extractive CEMS ME Test.

11.7.2.1 Introduce reference gases to the CEMS probe, prior to the sample conditioning and filtration system.

11.7.2.2 Measure three upscale HCl reference gas concentrations in the range shown in Table 4 of this PS.

11.7.2.3 Introduce the gases into the sampling probe with sufficient flow rate to replace the entire source gas sample.

11.7.2.4 Continue to add the reference gas until the response is stable as evidenced when the difference between two consecutive measurements is less than the LOD or within five percent of each other.

11.7.2.5 Make triplicate measurements for each reference gas for a total of nine measurements. Introduce different reference gas concentrations in any order but do not introduce the same gas concentration twice in succession.

11.7.2.6 At each reference gas concentration, determine the average of the three CEMS responses ($\overline{MC_l}$). Calculate the ME using Equation 3A in section 12.3.

11.7.2.7 If you desire to determine the system RT during this test, you must inject zero gas immediately before and after each injection of the high-level gas standard.

11.7.2.8 For non-dilution systems, you may adjust the system to maintain the correct flow rate at the analyzer during the test, but you may not make adjustments for any other purpose. For dilution systems, you must operate the measurement system at the appropriate dilution ratio during all system ME checks, and you may make only the adjustments necessary to maintain the proper ratio.

11.7.3 IP–CEMS ME Test.

11.7.3.1 Conduct a 3-level system ME test by individually adding the known concentrations of HCl reference gases into a calibration cell of known volume, temperature, pressure and path length.

Note: The optical path used for IP–CEMS ME checks must include the native HCl measurement path. You must also collect native stack concentration HCl measurements before and after each HCl standard measurement. Bracketing HCl reference gas measurements with native stack HCl measurements must be used in the calculations in Equation 5 in section 12.4.2 to correct the upscale measurements for stack gas HCl concentration changes.

11.7.3.2 Introduce HCl reference gas into your calibration cell in a range of concentrations that produce responses equivalent to the source concentrations shown in Table 4 of this PS for your path length.

11.7.3.3 Make triplicate measurements for each reference gas standard for a total of nine measurements. Introduce different calibration concentrations in any order but do not introduce the same reference gas concentration twice in succession.

11.7.3.4 You must calculate the effective concentration ($C_{i,eff}$) of the HCl reference gas equivalent to the stack concentration by correcting for calibration cell temperature, pressure, path length, line strength factor (LSF) and, if necessary, the native stack gas HCl concentration using Equation 4 in section 12.0.

11.7.3.5 You may use the LSF provided by your instrument manufacturer or determine an instrument-specific LSF as a function of temperature using a heated gas cell and equivalent concentrations ($C_{i,eff}$) between 50 and 150 percent of the emission limit.

11.7.3.6 At each reference gas concentration, average the three independent CEMS measurement responses corrected for native HCl stack concentration. Calculate the ME using Equation 6A in section 12.4.3.

11.7.4 You may use Figure 1 in section 17.0 to record and report your ME test results.

11.7.5 If the ME specification in section 13.3 is not met for all three reference gas concentrations, take corrective action and repeat the test until an acceptable 3-level ME test is achieved.

11.8 Seven-Day Calibration Drift (CD) Test

11.8.1 The CD Test Period. Prior to the start of the RA tests, you must perform a seven-day CD test. The purpose of the seven-day CD test is to verify the ability of the CEMS to maintain calibration for each of seven consecutive unit operating days as specified in section 11.8.5 of this PS.

11.8.2 The CD tests must be performed using the zero gas and mid-level reference gas standards as defined in Table 4 of this PS.

11.8.3 Conduct the CD test on each day during continuous operation of the CEMS and normal facility operations following the procedures in section 11.7 of this PS, except that the zero gas and mid-level gas need only be introduced to the measurement system once each.

11.8.4 If periodic automatic or manual adjustments are made to the CEMS zero and upscale response factor settings, conduct the CD test immediately before these adjustments.

Note: Automatic signal or mathematical processing of all measurement data to determine emission results may be performed throughout the entire CD process.

11.8.5 Determine the magnitude of the CD at approximately 24-hour intervals, for 7 consecutive unit operating days. The 7 consecutive unit operating days need not be 7 consecutive calendar days.

11.8.6 Record the CEMS response for single measurements of zero gas and mid-level reference gas. You may use Figure 2 in section 17 of this PS to record and report the results of your 7-day CD test.

11.8.6.1 For extractive CEMS, calculate the CD using Equation 3B in section 12.3. Report the absolute value of the differences as a percentage of the span value.

11.8.6.2 For IP–CEMS, you must include the source measurement optical path while performing the upscale CD measurement; you must exclude the source measurement optical path when determining the zero gas concentration. Calculate the CD for IP CEMS using Equations 4, 5, 6B, and 7 in section 12.4.

11.8.7 The zero-level and mid-level CD for each day must be less than 5.0 percent of the span value as specified in section 13.2 of this PS. You must meet this criterion for 7 consecutive operating days past the 7-day CD test.

11.8.8 Dynamic Spiking Option for Seven-Day CD Test. For extractive CEMS, you have the option to conduct a mid-level dynamic spiking procedure for each of the 7 days in lieu of the mid-level reference gas injection described in sections 11.8.2 and 11.8.3. If this option is selected, the daily zero CD check is still required.

11.8.8.1 To conduct each of the seven daily mid-level dynamic spikes, you must use the DS procedure described in appendix A of this PS using a single spike of the mid-level reference gas (*see* Table 4).

11.8.8.2 You must perform the dynamic spike procedure by passing the spiked source gas sample through all filters, scrubbers, conditioners and other monitoring system components used during normal sampling, and as much of the sampling probe as practical.

11.8.8.3 Calculate the mid-level CD as a percent of span using Equation A6 of appendix A to this PS and calculate the zero drift using Equation 3B in section 12.3. Record and report the results as described in sections 11.8.6 and 11.8.7.

11.9 Relative Accuracy Test

11.9.1 Unless otherwise specified in an applicable regulation, use Method 26A in 40 CFR part 60, appendix A–8, Method 320 or Method 321, both found in 40 CFR part 63, appendix A, or ASTM D6348–12 including all annexes, as applicable, as the RMs for HCl measurement. Obtain and analyze RM audit samples, if they are available, concurrently with RM test samples according to the same procedure specified for performance tests in the general provisions of the applicable part. If Method 26 is not specified in an applicable subpart of the regulations, you may request approval to use Method 26 in appendix A–8 to this part as the RM on a site-specific basis under §§ 63.7(f) or 60.8(b). Other RMs for moisture, O_2, etc., may be necessary. Conduct the RM tests in such a way that they will yield results representative of the emissions from the source and can be compared to the CEMS data.

11.9.1.1 When Method 26A is used as the RM, you must sample sufficient gas to reach three times your method detection limit for Method 26A in 40 CFR part 60, appendix A–8, or for a minimum of one hour, whichever is greater.

11.9.1.2 When Method 320 or Method 321, both found in 40 CFR part 63, appendix A, or ASTM D6348–12, are used as the RM, you must collect gas samples that are at stack conditions (hot and wet) and you must traverse as required in section 11.9.3.

11.9.2 Conduct the diluent (if applicable), moisture (if needed), and pollutant measurements simultaneously. However, diluent and moisture measurements that are taken within an hour of the pollutant measurements may be used to calculate dry pollutant concentration and emission rates.

11.9.3 Reference Method Measurement Location and Traverse Point(s) Selection.

11.9.3.1 Measurement Location. Select, as appropriate, an accessible RM measurement location at least two equivalent diameters downstream from the nearest control device, point of pollutant generation, or other point at which a change in the pollutant concentration or emission rate may occur, and at least one half equivalent diameter upstream from the effluent exhaust or a control device. When pollutant concentration changes are due solely to diluent leakage (*e.g.,* air heater leakages) and pollutants and diluents are simultaneously measured at the same location, a half diameter may be used in lieu of two equivalent diameters. The equivalent duct diameter is calculated according to Method 1 in appendix A–1 to this part. The CEMS and RM sampling locations need not be the same.

11.9.3.2 Traverse Point Selection. Select traverse points that assure acquisition of representative RM samples over the stack or duct cross section according to one of the following options: (a) sample at twelve traverse points located according to section 11.3 of Method 1 in appendix A–1 to this part, (b) sample at 6 Method 1 traverse points according to section 6.5.6(b)(1) of appendix A to part 75 of this chapter, or (c) sample at three points on a measurement line (''3-point long line'') that passes through the centroidal area of the duct in the direction of any potential stratification. If this line interferes with the CEMS measurements, you may displace the line up to 20 cm (12 in.) or 5.0 percent of the equivalent diameter of the cross section, whichever is less, from the centroidal area. Locate the three traverse points at 16.7, 50.0, and 83.3 percent of the measurement line. Alternatively, you may conduct a stratification test following the procedures in sections 11.9.3.2.1 through 11.9.3.2.4 to justify sampling at a single point or three points located on the measurement line at 0.4, 1.2, and 2.0 m from the stack wall (''3-point short line''). Stratification testing must be conducted at the sampling location to be used for the RM measurements during the RA test and must be made during normal facility operating conditions. You must evaluate the stratification by measuring the gas on the same moisture basis as the HCl CEMS (wet or dry). Stratification testing must be repeated for each RA test program to justify single point or ''3-point short line'' sampling.

11.9.3.2.1 Use a probe of appropriate length to measure the HCl concentration or an alternative analyte, as described in this section, using 12 traverse points located according to section 11.3 of Method 1 in appendix A–1 to 40 CFR part 60 for a circular stack or nine points at the centroids of similarly-shaped, equal area divisions of the cross section of a rectangular stack.

11.9.3.2.2 You may substitute a stratification test for SO_2 for the HCl stratification test. If you select this option, you must follow the test procedures in Method 6C of appendix A–4 to 40 CFR part 60 or Method 320 of appendix A of 40 CFR part 63.

11.9.3.2.3 Calculate the mean measured concentration for all sampling points (MN_{avg}).

11.9.3.2.4 Calculate the percent stratification (S_t) of each traverse point using Equation 8 in section 12.5.

11.9.3.2.5 The gas stream is considered to be unstratified and you may perform the RA testing at a single point that most closely matches the mean if the concentration at each traverse point differs from the mean concentration for all traverse points by: (a) No more than 5.0 percent of the mean concentration; or (b) 0.2 ppm (for HCl) or 3 ppm (for SO_2) absolute, whichever is less restrictive.

11.9.3.2.6 If the criterion for single point sampling (5.0 percent, 0.2 ppm for HCl or 3 ppm for SO_2 are not met, but the concentration at each traverse point differs from the mean concentration for all traverse points by no more than 10.0 percent of the mean, the gas stream is considered to be minimally stratified, and you may take RA samples using the ''3-point short line''. Alternatively, you may use the 3-point short line if each traverse point differs from the mean value by no more than 0.4 ppm (for HCl) or 5 ppm (for SO_2).

11.9.3.2.7 If the concentration at any traverse point differs from the mean concentration by more than 10 percent, the gas stream is considered stratified and you must sample using one of the options in section 11.9.3.2 above.

11.9.3.3 Conduct all necessary RM tests within 3 cm (1.2 in.) of the traverse points, but no closer than 3 cm (1.2 in.) to the stack or duct wall.

11.9.4 In order to correlate the CEMS and RM data properly, record the beginning and end of each RM run (including the time of day in hours, minutes, and seconds) using a clock synchronized with the CEM clock used to create a permanent time record with the CEMS output.

11.9.5 You must conduct the RATA during representative process and control operating conditions or as specified in an applicable regulation, permit or subpart.

11.9.6 Conduct a minimum of nine RM test runs. *NOTE:* More than nine RM test runs may be performed. If this option is chosen, up to three test run results may be excluded so long as the total number of test run results used to determine the CEMS RA is greater than or equal to nine. However, all data must be reported including the excluded test runs.

11.9.7 Analyze the results from the RM test runs using Equations 9–14 in section 12.6. Calculate the RA between the CEMS results and the RM.

11.10 Record Keeping and Reporting

11.10.1 For systems that use a liquid evaporative standard generator to deliver HCl reference gas standards, record supporting data for these devices, including liquid feed calibrations, liquid standard concentration(s) and NIST-traceability, feed rate and gas flow calibrations for all diluent and HCl gas flows. All calibrations must include a stated uncertainty, and the combined uncertainty of the delivered HCl reference gas concentration must be calculated and reported.

11.10.2 Record the results of the CD test, the RT test, the ME test, the RA test, and for IP–CEMS, the results of the beam intensity, temperature and pressure verification procedures. Also keep records of the RM and CEMS field data, calculations, and reference gas certifications necessary to confirm that the performance of the CEMS met the performance specifications.

11.10.3 For systems that use Method 205 to prepare HCl reference gas standards, record results of Method 205 performance test field evaluation, reference gas certifications, and gas dilution system calibration.

11.10.4 Record the LOD for the CEMS. For extractive CEMS, record the LOD in ppmv. For IP–CEMS, record the LOD on a ppm-meter basis along with a calculation of the installation specific LOD in ppmv. For both CEMS types, you must also record the field verified SADL.

11.10.5 Record the results of the interference test.

11.10.6 Report the results of all certification tests to the appropriate regulatory agency (or agencies), in hardcopy and/or electronic format, as required by the applicable regulation or permit.

12.0 Calculations and Data Analysis

12.1 Nomenclature

C_i = Zero HCl reference gas concentration used for test i (ppmv);
$C_{i,eff}$ = Equivalent concentration of the reference gas value, C_i, at the specified conditions (ppmv);
CC = Confidence coefficient (ppmv);
$CD_{extractive}$ = Calibration drift for extractive CEMS (percent);
CD_{IP} = Calibration drift for IP–CEMS (percent);
CD_0 = Calibration drift at zero HCl concentrations for an IP–CEMS (percent);
d_{avg} = Mean difference between CEMS response and the reference gas (ppmv);
d_i = Difference of CEMS response and the RM value (ppmv);
I = Total interference from major matrix stack gases, (percent);
LSF = Line strength factor for IP–CEMS instrument specific correction for temperature and gas matrix effects derived from the HITRAN and/or manufacturer specific database (unitless);
ΔMC_{avg} = Average of the 3 absolute values of the difference between the measured HCl reference gas concentrations with and without interference from selected stack gases (ppmv);
MC_i = Measured zero or HCl reference gas concentration i (ppmv);
$\overline{MC_i}$ = Average of the measured zero or HCl reference gas concentration i (ppmv);
MC_{int} = Measured HCl concentration of the HCl reference gas plus the individual or combined interference gases (ppmv);
$ME_{extractive}$ = Measurement error for extractive CEMS (percent);
ME_{IP} = Measurement error for IP–CEMS (percent);
MN_{avg} = Average concentration at all sampling points (ppmv);
MN_{bi} = Measured native concentration bracketing each calibration check measurement (ppmv);
MN_i = Measured native concentration for test or run i (ppmv);
n = Number of measurements in an average value;
PL_{Cell} = Path length of IP–CEMS calibration cell (m);
PL_{Stack} = Path length of IP–CEMS stack optical path (m);
RA = Relative accuracy of CEMS compared to a RM (percent);
RM_i = RM concentration for test run i (ppmv);
RM_{avg} = Mean measured RM value (ppmv);
S = Span of the instrument (ppmv);
S_d = Standard deviation of the differences (ppmv);
S_{ti} = Stratification at traverse point i (percent);
SADL = Standard addition detection level (ppmv);
$t_{0.975}$ = One-sided t-value at the 97.5th percentile obtained from Table 5 in section 17.0 for n–1 measurements;
$T_{reference}$ = Temperature of the calibration cell for IP–CEMS (degrees Kelvin);
T_{stack} = Temperature of the stack at the monitoring location for IP–CEM (degrees Kelvin).

12.2 Calculate the Difference Between the Measured HCl Concentration With and Without Interferents for Each Interference Gas (Or Mixture) for Your CEMS as:

$$\Delta MC_{avg} = \frac{\sum_{i=1}^{3} |MC_i - MC_{int}|}{3} \qquad \text{Eq. 1}$$

Calculate the total percent interference as:

$$I = \sum_{i=1}^{n} \frac{\Delta MC_{avg}}{MC_i} * 100 \qquad \text{Eq. 2}$$

12.3 Calculate the ME or CD at Concentration i for an Extractive CEMS as:

$$ME_{extractive} = \frac{|C_i - \overline{MC_i}|}{S} * 100 \qquad \text{Eq. 3A}$$

$$CD_{extractive} = \frac{|C_i - MC_i|}{S} * 100 \qquad \text{Eq. 3B}$$

12.4 Calculate the ME or CD at Concentration i for IP–CEMS That Use a Calibration Cell as Follows:

12.4.1 Calculate the equivalent concentration $C_{i,eff}$ using Equation 4:

$$C_{i,eff} = \left[C_i \times \frac{PL_{cell}}{PL_{Stack}} \times \frac{T_{stack}}{T_{reference}} \times LSF \right] \qquad \text{Eq. 4}$$

12.4.2 Calculate the average native concentration before and after each calibration check measurement as:

$$MN_{bi} = \frac{MN_i + MN_{i+1}}{2} \qquad \text{Eq. 5}$$

12.4.3 Calculate the ME or CD at concentration i for an IP–CEM as:

$$ME_{IP} = \frac{\sum_1^3 \left|(MC_i - MN_{bi}) - C_{ieff}\right|}{3S} * 100 \qquad \text{Eq. 6A}$$

$$CD_{IP} = \frac{\left|MC_i - MN_{bi} - C_{i,eff}\right|}{S} * 100 \qquad \text{Eq. 6B}$$

12.4.4 Calculate the zero CD as a percent of span for an IP–CEMS as:

$$CD_0 = \frac{|MC_i - MC_{i+1}|}{S} * 100 \qquad \text{Eq. 7}$$

12.5 Calculate the Percent Stratification at Each Traverse Point as:

$$S_{ti} = \frac{|MN_i - \mathrm{MN_{avg}}|}{MN_{avg}} * 100 \qquad \text{Eq. 8}$$

12.6 Calculate the RA Using RM and CEMS Data

12.6.1 Determine the CEMS final integrated minute average pollutant concentration or emission rate for each RM test period. Consider system RT, if important, and confirm that the results have been corrected to the same moisture, temperature and diluent concentration basis.

12.6.2 When Method 26A (or if approved for use, Method 26), found in 40 CFR part 60, appendix A–8 of this part, is used as the RM, compare each CEMS integrated average value against the corresponding RM value for identical test periods. Make these comparisons on the same basis (*e.g.,* wet, dry, ppmv, or units of the standard). To convert results generate by Method 26A or 26 in mg/DSCM to ppmv, use the conversion factor 0.662 ppm/(mg/DSCM).

12.6.3 If the RM is Method 320 or Method 321, found in 40 CFR part 63, appendix A, or ASTM D6348–12, make a direct comparison of the average RM results and CEMS average value for identical test periods.

12.6.4 For each test run, calculate the arithmetic difference of the RM and CEMS results using Equation 9.

$$d_i = RM_i - MN_i \qquad \text{Eq. 9}$$

12.6.5 Calculate the standard deviation of the differences (S_d) of the CEMS measured and RM results using Equation 10.

$$S_d = \sqrt{\frac{\sum_i^n \left(d_i - \left(\frac{\sum_{i=1}^n d_i}{n}\right)\right)^2}{n-1}} \qquad \text{Eq. 10}$$

12.6.6 Calculate the confidence coefficient (CC) for the RATA using Equation 11.

$$CC = t_{0.975} * \left(\frac{S_d}{(n^{1/2})}\right) \qquad \text{Eq. 11}$$

12.6.7 Calculate the mean difference (d_{avg}) between the RM and CEMS values in the units of ppmv or the emission standard using Equation 12.

$$d_{avg} = \frac{1}{n}\sum_{i=1}^n d_i \qquad \text{Eq. 12}$$

12.6.8 Calculate the average RM value using Equation 13.

$$RM_{avg} = \frac{1}{n}\sum_{i=1}^n RM_i \qquad \text{Eq. 13}$$

12.6.9 Calculate RA of the CEMS using Equation 14.

$$RA = \left[\left(\left|d_{avg}\right| + CC\right)/RM_{avg}\right] * 100 \qquad \text{Eq. 14}$$

13.0 Method Performance

13.1 Level of Detection. You may not use a CEMS whose LOD or SADL is greater than 20 percent of the applicable regulatory limit or other action level for the intended use of the data.

13.2 Calibration Drift. The zero- and mid-level calibration drift for the CEMS must not exceed 5.0 percent of the span value for 7 consecutive operating days.

13.3 Measurement Error. The ME must be less than or equal to 5.0 percent of the span value at the low-, mid-, and high-level reference gas concentrations.

13.4 Relative Accuracy. Unless otherwise specified in an applicable regulation or permit, the RA of the CEMS, whether calculated in units of HCl concentration or in units of the emission standard, must be less than or equal to 20.0 percent of the RM when RM_{avg} is used in the denominator of Equation 14.

13.4.1 In cases where the RA is calculated on a concentration (ppmv) basis, if the average RM emission level for the test is less than 75 percent of the HCl concentration equivalent to the emission standard, you may substitute the HCl concentration equivalent to the standard in the denominator of Equation 14 in place of RM_{avg}.

13.4.2 Similarly, if the RA is calculated in units of the emission standard and the HCl emission level measured by the RMs is less than 75 percent of the emission standard, you may substitute the emission standard in the denominator of Equation 14 in place of RM_{avg}.

13.4.3 The alternative calculated RA in paragraph 13.4.1 or 13.4.2 must be less than or equal to 15.0 percent.

13.5 Interference Test.

13.5.1 The sum of the interference response(s) from Equation 2 must not be greater than 2.5 percent of the calibration span or ±3.0 percent of the equivalent HCl concentration used for the interference test, whichever is less restrictive. The results are also acceptable if the sum of the interference response(s) does not exceed six times the LOD or 0.5 ppmv for a calibration span of 5 to 10 ppm, or 0.2 ppmv for a calibration span of less than 5 ppmv.

13.6 IP–CEMS Beam Intensity Test. For IP–CEMS, the percent difference between the measured concentration with and without attenuation of the light source must not exceed ±3.0 percent.

13.7 IP–CEMS Temperature Measurement Verification. Your temperature sensor satisfies the accuracy required if the absolute relative difference between measured value of stack temperature (M_t) and the temperature value from the calibrated temperature reference device (V_t) is ≤1.0 percent or if the absolute difference between M_t and V_t is ≤2.8° C (5.0 °F), whichever is less restrictive.

13.8 IP–CEMS Pressure Sensor Measurement Verification. Your pressure sensor satisfies the accuracy required if the absolute relative difference between the measured value of stack pressure (M_P) and the pressure value from the calibrated pressure reference device (V_P) is ≤5.0 percent or if the absolute difference between M_p and V_P is ≤0.12 kilopascals (0.5 inches of water column), whichever is less restrictive.

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 Bibliography

1. Method 318—Extractive FTIR Method for the Measurement of Emissions From the Mineral Wool and Wool Fiberglass Industries, 40 CFR, part 63, subpart HHHHHHH, appendix A.

2. ''EPA Protocol for the Use of Extractive Fourier Transform Infrared (FTIR) Spectrometry in Analyses of Gaseous Emissions from Stationary Industrial Sources,'' February, 1995.

3. ''Measurement of Gaseous Organic and Inorganic Emissions by Extractive FTIR Spectroscopy,'' EPA Contract No. 68–D2–0165, Work Assignment 3–08.

4. ''Method 301—Field Validation of Pollutant Measurement Methods from Various Waste Media,'' 40 CFR part 63, appendix A.

5. EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, U.S. Environmental Protection Agency office of Research and Development, EPA/600/R–12/531, May 2012.

17.0 Tables, Diagrams, Flowcharts, and Validation Data

TABLE 1—INTERFERENCE TEST GAS CONCENTRATIONS

Potential interferent gas [1]	Approximate concentration (balance N_2)
CO_2	15% ± 1% CO_2.[2]
CO	100 ± 20 ppm.
CH_2O	20 ± 5 ppm.
CH_4	100 ± 20 ppm.
NH_3	10 ± 5 ppm (extractive CEMS only).
NO_2	250 ± 50 ppm.
SO_2	200 ± 20 ppm.
O_2	3% ± 1% O_2.[2]
H_2O	10% ± 1% H_2O.[2]
N_2	Balance.[2]

[1] Any of these specific gases can be tested at a lower level if the manufacturer has provided reliable means for limiting or scrubbing that gas to a specified level in CEMS field installations.

[2] Gases for short path IP cell interference tests cannot be added above 100 percent stack equivalent concentration. Add these gases at the indicated percentages to make up the remaining cell volume.

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Table 2. Example Interference Test Data Sheet

Date of Test:
Analyzer Type:
Model No.:
Serial No.:
Span:
Test Organization:
Test Personnel:

Interference Gas or Gas Combination	HCl Concentration (ppmv)	HCl Concentration (ppmv) w/Interference	Absolute Difference (ppmv)	Average Absolute Difference (ppmv)
Sum of Interference Responses				
Percent of Baseline Concentration				
Percent of Span				

BILLING CODE C

TABLE 3—DESIGN STANDARDS FOR TEMPERATURE SENSORS

If the sensor is a . . .	You can use the following design standards as guidance in selecting a sensor for your IP–CEMS
1. Thermocouple	a. ASTM E235–88 (1996), ‘‘Specification for Thermocouples, Sheathed, Type K, for Nuclear or Other High-Reliability Applications.’’ b. ASTM E585/E585M–04, ‘‘Specification for Compacted Mineral-Insulated, Metal-Sheathed, Base Metal Thermocouple Cable.’’ c. ASTM E608/E608M–06, ‘‘Specification for Mineral-Insulated, Metal-Sheathed Base Metal Thermocouples.’’ d. ASTM E696–07, ‘‘Specification for Tungsten-Rhenium Alloy Thermocouple Wire.’’ e. ASTM E1129/E1129M–98 (2002), ‘‘Standard Specification for Thermocouple Connectors.’’ f. ASTM E1159–98 (2003), ‘‘Specification for Thermocouple Materials, Platinum-Rhodium Alloys, and Platinum.’’ g. ISA–MC96.1–1982, ‘‘Temperature Measurement Thermocouples.’’
2. Resistance temperature detector.	ASTM E1137/E1137M–04, ‘‘Standard Specification for Industrial Platinum Resistance Thermometers.’’

TABLE 4—PERFORMANCE SPECIFICATION TEST ZERO AND REFERENCE GAS RANGES

Test	Units	HCl Zero and Reference Gas Concentrations in Terms of Percent of Span[a]				Section
		Zero	Low Level	Mid Level	High Level	
Calibration Drift	% of Span	<LOD	NA	50–60[b]	NA	11.8
Measurement Error	% of Span	NA	20–30	50–60	80–100	11.7

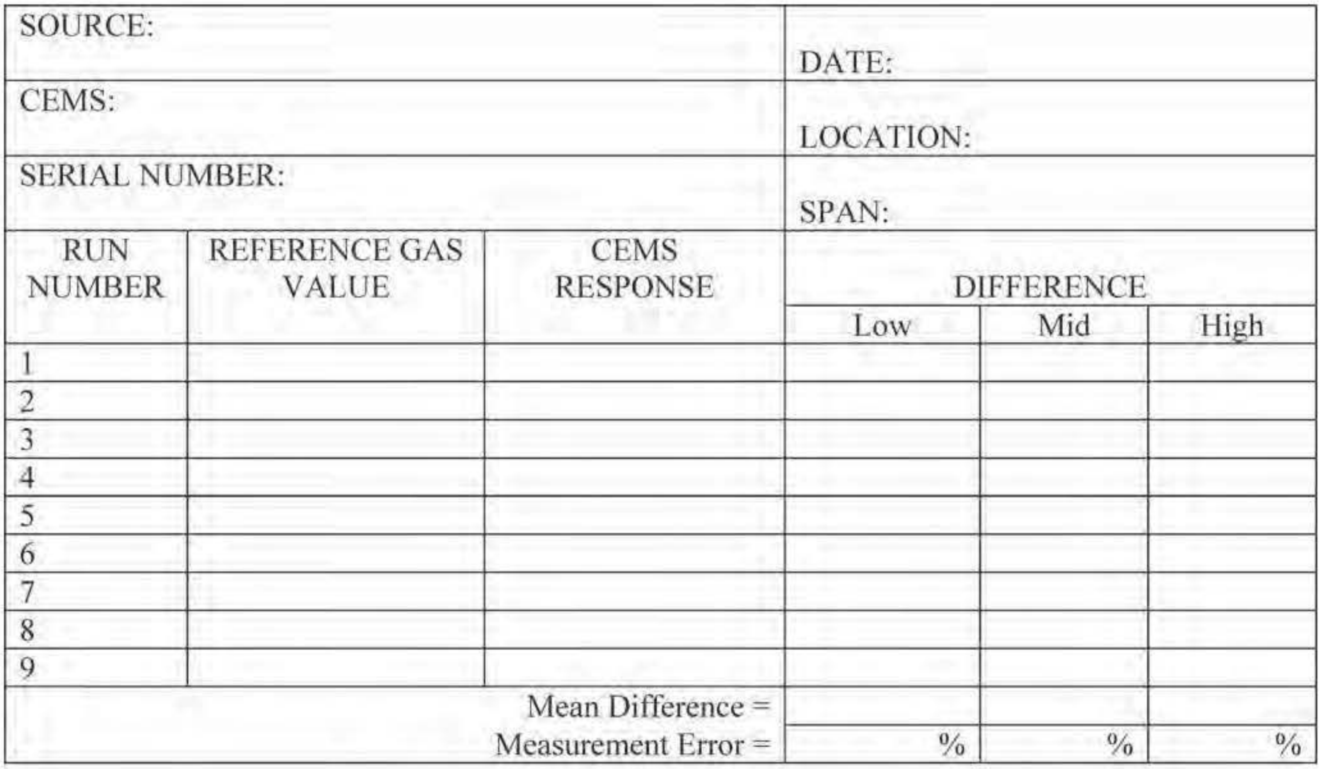
[a] Reference gas concentration must be NIST traceable. (see section 7.1)

[b] Mid-level is required. For DS calibration drift option, choose a concentration that yields a value in this range at the analyzer.

TABLE 5—STUDENT’S t-VALUES

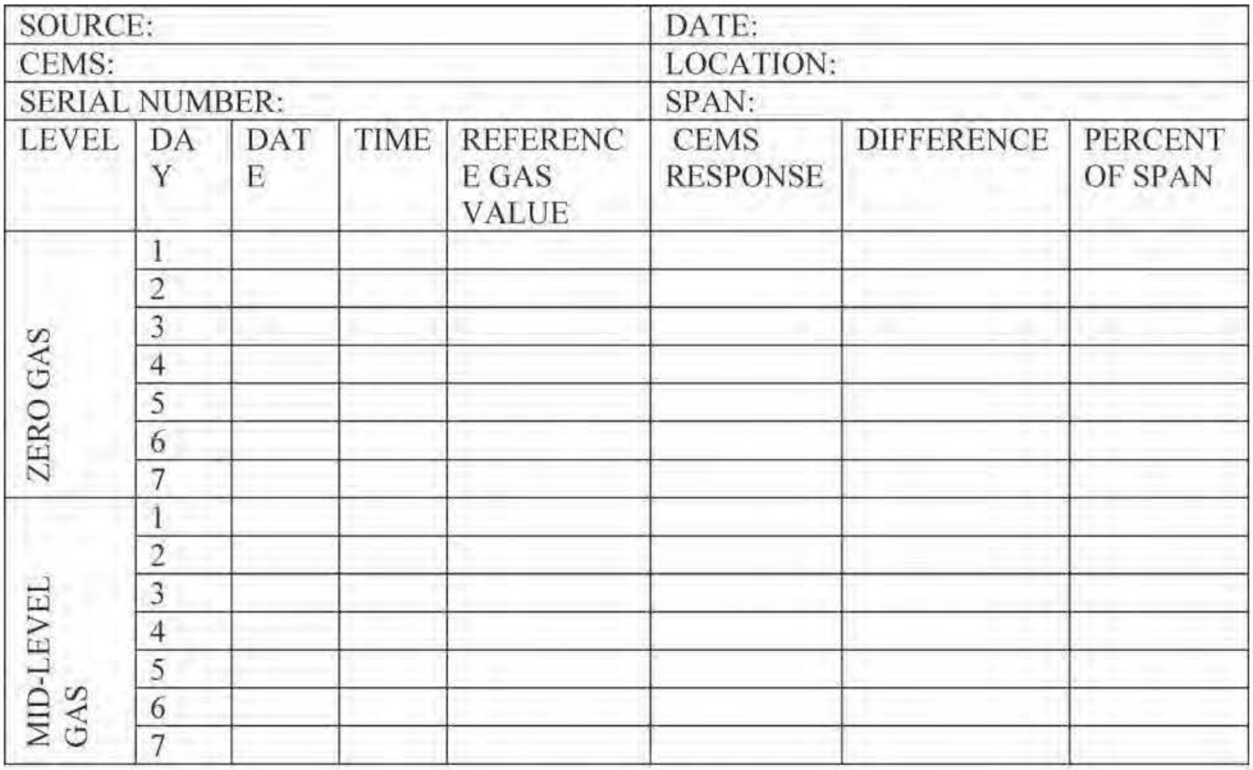
n-1[a]	t-value	n-1[a]	t-value	n-1[a]	t-value
1	12.71	11	2.201	21	2.080
2	4.303	12	2.179	22	2.074
3	3.182	13	2.160	23	2.069
4	2.776	14	2.145	24	2.064
5	2.571	15	2.131	25	2.060
6	2.447	16	2.120	26	2.056
7	2.365	17	2.110	27	2.052
8	2.306	18	2.101	28	2.048
9	2.262	19	2.093	29	2.045
10	2.228	20	2.086	30	2.042

[a] The value n is the number of independent pairs of measurements. Either discrete (independent) measurements in a single run, or run averages can be used.



SOURCE:			DATE:		
CEMS:			LOCATION:		
SERIAL NUMBER:			SPAN:		
RUN NUMBER	REFERENCE GAS VALUE	CEMS RESPONSE	DIFFERENCE		
			Low	Mid	High
1					
2					
3					
4					
5					
6					
7					
8					
9					
		Mean Difference =			
		Measurement Error =	%	%	%

Figure 1. Measurement Error Determination



SOURCE:					DATE:		
CEMS:					LOCATION:		
SERIAL NUMBER:					SPAN:		
LEVEL	DAY	DATE	TIME	REFERENCE GAS VALUE	CEMS RESPONSE	DIFFERENCE	PERCENT OF SPAN
ZERO GAS	1						
	2						
	3						
	4						
	5						
	6						
	7						
MID-LEVEL GAS	1						
	2						
	3						
	4						
	5						
	6						
	7						

Figure 2. Calibration Drift Determination

PS–18 Appendix A Standard Addition Procedures

1.0 Scope and Application

1.1 This appendix to Performance Specification (PS) 18 describes the procedure and performance requirements for standard addition (SA) as a quality check for hydrogen chloride (HCl) continuous emission monitoring systems (CEMS).

1.2 This appendix is applicable to quality checks of both extractive and integrated path (IP) technologies used to measure HCl emissions.

1.3 For extractive CEMS, this procedure must be used, as a level of detection (LOD) verification of all field-installed CEMS. Additionally, it is allowed by Procedure 6 in appendix F to this part as an alternative to upscale calibration drift (CD) tests, cylinder gas audits and relative accuracy audits (RAAs), and may be used for quality assurance purposes under other applicable regulations or permits that require HCl monitoring.

1.4 For IP–CEMS, this procedure must be used as a LOD verification of all field-installed CEMS.

2.0 Summary of the Appendix for Standard Addition

As used here, SA is a gas phase method of standard additions (either static or dynamic) used to verify the accuracy of CEMS measurements in the presence of the sample matrix. For extractive CEMS, it consists of spiking a known quantity of HCl dynamically into the measurement system as an addition to the native HCl and the native source gas matrix. For IP–CEMS, this procedure consists of introducing a known quantity of HCl into the optical path that also includes the native source gas.

3.0 Definitions. (See PS–18 and Procedure 6 of Appendix F to Part 60 for the Definitions Used in This Appendix.)

4.0 Interferences. Interferences are discussed in PS–18, section 4.0

5.0 *Safety.* The procedures required under this appendix may involve hazardous materials, operations and equipment. This procedure may not address all of the safety problems associated with these procedures. You as the facility or operator must establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performing these procedures. As the CEMS user, you should consult instrument operation manuals, material safety data sheets, compressed gas safety requirements, and other Occupational Safety and Health Administration regulations for specific precautions to be taken.

6.0 *Equipment and Supplies.* An example of equipment and supplies is described in section 6 of PS–18.

7.0 *Reagents and Standards.* SA materials must meet the requirements defined for reference gases in section 7 of PS–18 to perform this procedure with the following exception. You may use gases certified by the gas vendor to +5 percent to perform the daily calibration drift assessment in section 4.1 of Procedure 6 in appendix F of this part.

Note: For extractive CEMS the concentrations of reference gases required for SA are likely to be significantly higher than the concentration of reference gases associated with PS–18 requirements.

8.0 *Standard Addition and Dynamic Spiking Procedure.* The standard addition procedure consists of measuring the native source gas concentration, addition of reference gas, and measurement of the resulting SA elevated source gas concentration. For extractive CEMS, HCl is spiked dynamically and thus, one must account for the dilution of sample gas from the addition of the HCl reference gas. For IP–CEMS, standard addition of an HCl reference gas is made by either adding an HCl reference gas to a flow through cell or inserting a sealed reference gas cell into the measurement path of the CEMS. The enclosed cell or a fixed cell must contain an HCl concentration that accounts for the difference in path length of the cell used for SA relative to the measurement path.

8.1 SA Concentration and Measurement Replicates.

8.1.1 You must inject HCl gas to create a measured concentration based on the requirements of the particular performance test (*e.g.,* LOD verification, CD, DSA).

8.1.2 Each dynamic spike (DS) or standard addition (SA) replicate consists of a measurement of the source emissions concentration of HCl (native stack concentration) with and without the addition of HCl. With a single CEMS, you must alternate the measurement of the native and SA-elevated source gas so that each measurement of SA-elevated source gas is immediately preceded and followed by a measurement of native stack gas. Introduce the SA gases in such a manner that the entire CEMS is challenged. Alternatively, you may use an independent continuous HCl monitor to measure the native source concentration before and after each standard addition as described in section 8.1.4.

8.1.3 Unless specified otherwise by an applicable rule, your SA-elevated concentration may not exceed 100 percent of span when the SA and native HCl concentration are combined.

8.1.4 As an alternative to making background measurements pre- and post-SA, you may use an independent continuous HCl monitor as a temporary unit to measure native stack HCl concentration while simultaneously using the CEMS to measure the SA-elevated source concentration. If you use an independent continuous HCl monitor you must make one concurrent background or native HCl measurement using both the installed CEMS and the independent continuous HCl monitor, immediately before the SA procedure in section 8.2 or 8.3 begins, to confirm that the independent monitoring system measures the same background concentration as the CEMS being qualified with this PS.

8.2 SA Procedure for Extractive CEMS (Dynamic Spiking)

8.2.1 Your HCl spike addition must not alter the total volumetric sample system flow rate or basic dilution ratio of your CEMS (if applicable).

8.2.2 Your spike gas flow rate must not contribute more than 10 percent of the total volumetric flow rate through the CEMS.

8.2.3 You must determine a dilution factor (DF) or relative concentration of HCl for each dynamic spike. Calibrated, NIST-traceable flow meters accurate to within 2.0 percent or highly accurate tracer gas measurements are required to make the necessary DF determinations at the accuracy required for this PS. Calibrated, NIST-traceable flow meters (*e.g.,* venturi, orifice) accurate to within 2.0 percent should be recertified against an NIST-traceable flow meter annually. **Note:** Since the spiking mass balance calculation is directly dependent on the accuracy of the DF determination, the accuracy of measurements required to determine the total volumetric gas flow rate, spike gas flow rate, or tracer gas standard addition concentration is critical to your ability to accurately perform the DS procedure and calculate the results.

8.2.4 You must monitor and record the total sampling system flow rate and sample dilution factor (DF) for the spiking and stack gas sampling systems to ensure they are known and do not change during the spiking procedure. Record all data on a data sheet similar to Table A1 in section 13 of this appendix.

8.2.4.1 You may either measure the spike gas flow and the total flow with calibrated flow meters capable of NIST traceable accuracy to ± 2.0 percent or calculate the flow using a stable tracer gas included in your spike gas standard.

8.2.4.2 If you use flow measurements to determine the spike dilution, then use Equation A1 in section 11.2.1 of this appendix to calculate the DF. Determination of the spike dilution requires measurement of HCl spike flow (Q_{spike}) and total flow through the CEM sampling system (Q_{probe}).

8.2.4.3 If your CEMS is capable of measuring an independent stable tracer gas, you may use a spike gas that includes the tracer to determine the DF using Equation A2 or A3 (sections 11.2.2 and 11.2.3 of this appendix) depending on whether the tracer gas is also present in the native source emissions.

8.2.4.4 For extractive CEMS, you must correct the background measurements of HCl for the dilution caused by the addition of the spike gas standard. For spiking systems that alternate between addition of HCl and zero gas at a constant DF, the background measurements between spikes will not be equal to the native source concentration.

8.2.5 Begin by collecting unspiked sample measurements of HCl. You must use the average of two unspiked sample measurements as your pre-spike background.

Note: Measurements should agree within 5.0 percent or three times the level of detection to avoid biasing the spike results.

8.2.5.1 Introduce the HCl gas spike into the permanent CEMS probe, upstream of the particulate filter or sample conditioning system and as close to the sampling inlet as practical.

8.2.5.2 Maintain the HCl gas spike for at least twice the DS response time of your CEMS or until the consecutive measurements agree within 5.0 percent. Collect two independent measurements of the native plus spiked HCl concentration.

8.2.5.3 Stop the flow of spike gas for at least twice the DS response time of your CEMS or until the consecutive measurements agree within 5.0 percent. Collect two independent measurements of the native HCl concentration.

8.2.6 Repeat the collection of sample measurements in section 8.2.5 until you have data for each spike concentration including a final set of unspiked sample measurements according to section 8.2.5.3.

8.2.7 Verify that the CEMS responded as expected for each spike gas injection, and that the data quality is not impacted by large shifts in the native source concentration. Discard and repeat any spike injections as necessary to generate a complete set of the required replicate spike measurements.

8.2.8 Calculate the standard addition response (SAR) for extractive CEMS, using Equation A4 in section 11.2, of this appendix.

8.2.9 If the DS results do not meet the specifications for the appropriate performance test in PS–18 or Procedure 6 of appendix F of this part, you must take corrective action and repeat the DS procedure.

8.3 SA Procedure for IP–CEMS (Static Spiking).

8.3.1 For IP–CEMS, you must make measurements of native source gas HCl concentration and an HCl standard addition using a calibration cell added to the optical measurement path.

8.3.2 Introduce zero gas into a calibration cell located in the optical measurement path of the instrument. Continue to flush the zero gas into the cell for at least the SA response time of your CEMS or until two consecutive measurements taken are within 5.0 percent, then collect two independent measurements. Alternatively you may measure native concentrations without the calibration cell in the optical path.

8.3.3 Introduce the HCl spike gas into the calibration cell. Continue to flush the spike gas into the cell for at least the SA response time of your CEMS or until two consecutive measurements taken are within 5.0 percent of one another. Then collect two independent measurements of the SA addition to the native concentration. Alternatively you may insert a sealed calibration cell, containing HCl at the appropriate concentration, into the optical path to measure the SA addition to the native concentration.

8.3.4 Repeat the collection of SA-elevated and native HCl measurements in sections 8.3.2 and 8.3.3 until you have data for each SA concentration. Then, make a final native HCl measurement. The measured concentrations must be corrected for calibration cell and stack temperature, pressure and stack measurement path length.

8.3.5 Calculate the standard addition response (SAR) for an IP–CEMS, using Equation A8 in section 11.3 of this appendix.

8.3.6 If the SA results do not meet the specifications for the appropriate performance test in PS–18 or Procedure 6 of appendix F of this part, you must take corrective action and repeat the SA procedure.

9.0 Quality Control [Reserved]

10.0 Calibration and Standardization [Reserved]

11.0 *Calculations and Data Analysis.* Calculate the SA response for each measurement and its associated native HCl measurement(s), using equations in this section. (**Note:** For cases where the emission standard is expressed in units of lb/MMBtu or corrected to a specified O_2 or CO_2 concentration, an absolute accuracy specification based on a span at stack conditions may be calculated using the average concentration and applicable conversion factors. The appropriate procedures for use in cases where a percent removal standard is more restrictive than the emission standard are the same as in 40 CFR part 60, PS–2, sections 12 and 13.)

11.1 Nomenclature.

C_{spike} = Actual HCl reference gas concentration spiked (*e.g.,* bottle or reference gas concentration) ppmv;
$C_{tracer\ spiked}$ = Tracer gas concentration injected with spike gas (‘‘reference concentration’’) ppmv;
DF = Spiked gas dilution factor;
DSCD = Calibration drift determined using DS procedure (percent);
DSE = Dynamic spike error (ppmv);
ESA = Effective spike addition (ppmv);
MC_{SA} = Measured SA-elevated source gas concentration (ppmv);
MC_{spiked} = Measured HCl reference gas concentration i (ppmv);
MC_{native} = Average measured concentration of the native HCl (ppmv);
$M_{native\ tracer}$ = Measured tracer gas concentration present in native effluent gas (ppmv);
$M_{spiked\ tracer}$ = Measured diluted tracer gas concentration in a spiked sample (ppmv);
Q_{spike} = Flow rate of the dynamic spike gas (Lpm);
Q_{probe} = Average total stack sample flow through the system (Lpm);
S = Span (ppmv);
SAR = Standard addition response (ppmv)

11.2 Calculating Dynamic Spike Response and Error for Extractive CEMS.

11.2.1 If you determine your spike DF using spike gas and stack sample flow measurements, calculate the DF using equation A1:

$$DF = \frac{Q_{spike}}{Q_{probe}} \qquad \text{Eq. A1}$$

11.2.2 If you determine your spike DF using an independent stable tracer gas that is not present in the native source emissions, calculate the DF for DS using equation A2:

$$DF = \frac{M_{spiked\ tracer}}{C_{tracer\ spiked}} \qquad \text{Eq. A2}$$

11.2.3 If you determine your spike dilution factor using an independent stable tracer that is present in the native source emissions, calculate the dilution factor for dynamic spiking using equation A3:

$$DF = \frac{M_{spiked\ tracer} - M_{native\ tracer}}{C_{native\ tracer} - M_{native\ tracer}} \qquad \text{Eq. A3}$$

11.2.4 Calculate the SA response using Equation A4:

$$SAR = MC_{spiked} - (1 - DF) * MC_{native} \qquad \text{Eq. A4}$$

11.2.5 Calculate the DS error using Equation A5.

$$DSE = MC_{spiked} - MC_{native} - DF * (C_{spike} - MC_{native}) \qquad \text{Eq. A5}$$

11.2.6 Calculating CD using DS. When using the DS option for determining mid-level CD, calculate the CD as a percent of span using equation A6:

$$DSCD = \frac{|DSE|}{S} \qquad \text{Eq. A6}$$

11.2.7 The effective spike addition (ESA) is the expected increase in the measured concentration as a result of injecting a spike. Calculate ESA using Equation A7:

$$ESA = DF * (C_{spike} - MC_{native}) \qquad \text{Eq. A7}$$

11.3 Standard Addition Response for IP–CEMS. If you use an IP–CEMS and a calibration cell, calculate the SA response using Equation A8.

$$SAR = MC_{SA} - MC_{native} \qquad \text{Eq. A8}$$

13. Tables and Figures.

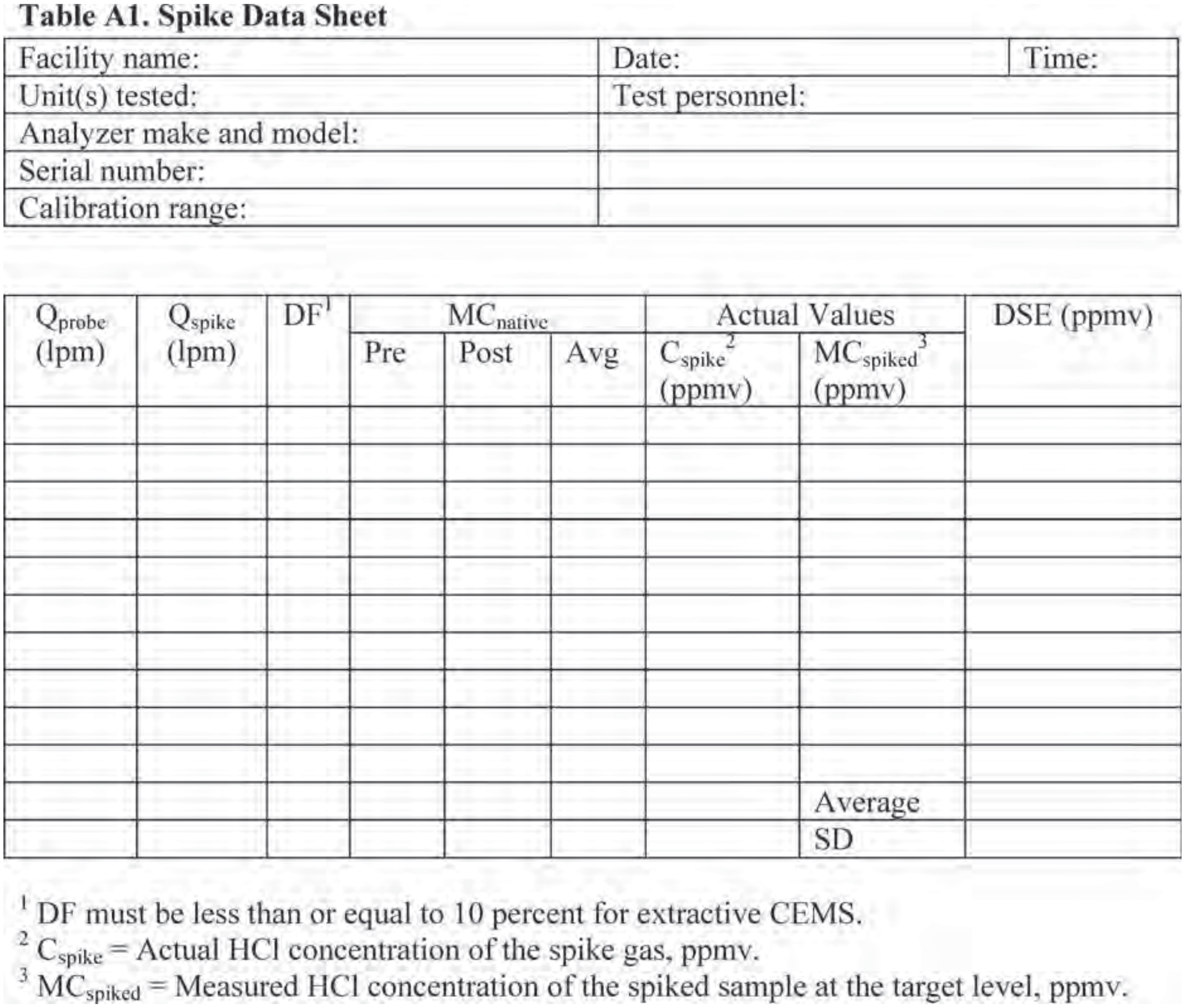


Table A1. Spike Data Sheet

Facility name:	Date:	Time:
Unit(s) tested:	Test personnel:	
Analyzer make and model:		
Serial number:		
Calibration range:		

Q_{probe} (lpm)	Q_{spike} (lpm)	DF[1]	MC_{native}			Actual Values		DSE (ppmv)
			Pre	Post	Avg	C_{spike}[2] (ppmv)	MC_{spiked}[3] (ppmv)	
							Average	
							SD	

[1] DF must be less than or equal to 10 percent for extractive CEMS.

[2] C_{spike} = Actual HCl concentration of the spike gas, ppmv.

[3] MC_{spiked} = Measured HCl concentration of the spiked sample at the target level, ppmv.

■ 3. Appendix F to part 60 is amended by adding Procedure 6 to read as follows:

Appendix F to Part 60—Quality Assurance Procedures

* * * * *

Procedure 6. Quality Assurance Requirements for Gaseous Hydrogen Chloride (HCl) Continuous Emission Monitoring Systems Used for Compliance Determination at Stationary Sources

1.0 Applicability and Principle

1.1 Applicability. Procedure 6 is used to evaluate the effectiveness of quality control (QC) and quality assurance (QA) procedures and evaluate the quality of data produced by any hydrogen chloride (HCl) gas, CAS: 7647–01–0, continuous emission monitoring system (CEMS) that is used for determining compliance with emission standards for HCl on a continuous basis as specified in an applicable permit or regulation.

1.1.1 This procedure specifies the minimum QA requirements necessary for the control and assessment of the quality of CEMS data submitted to the Environmental Protection Agency (EPA) or a delegated authority. If you are responsible for one or more CEMS used for HCl compliance monitoring you must meet these minimum requirements and you are encouraged to develop and implement a more extensive QA program or to continue such programs where they already exist.

1.1.2 Data collected as a result of QA and QC measures required in this procedure are to be submitted to the EPA or the delegated authority in accordance with the applicable regulation or permit. These data are to be used by both the delegated authority and you, as the CEMS operator, in assessing the effectiveness of the CEMS QC and QA procedures in the maintenance of acceptable CEMS operation and valid emission data.

1.2 Principle

1.2.1 The QA procedures consist of two distinct and equally important functions. One function is the assessment of the quality of the CEMS data by estimating accuracy. The other function is the control and improvement of the quality of the CEMS data by implementing QC policies and corrective actions. These two functions form an iterative control loop. When the assessment function indicates that the data quality is inadequate, the control effort must be increased until the data quality is acceptable. In order to provide uniformity in the assessment and reporting of data quality, this procedure specifies the assessment procedures to evaluate response drift and accuracy. The procedures specified are based on Performance Specification 18 (PS–18) in appendix B to this part.

(**Note:** Because the control and corrective action function encompasses a variety of policies, specifications, standards and corrective measures, this procedure treats QC requirements in general terms to allow you, as source owner or operator to develop the most effective and efficient QC system for your circumstances.)

2.0 Definitions

See PS–18 of this subpart for the primary definitions used in this Procedure.

3.0 QC Requirements

3.1 You, as a source owner or operator, must develop and implement a QC program. At a minimum, each QC program must include written procedures and/or manufacturer's information which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

(a) Calibration Drift (CD) checks of CEMS;

(b) CD determination and adjustment of CEMS;

(c) Integrated Path (IP) CEMS temperature and pressure sensor accuracy checks;

(d) IP CEMS beam intensity checks;

(e) Routine and preventative maintenance of CEMS (including spare parts inventory);

(f) Data recording, calculations, and reporting;

(g) Accuracy audit procedures for CEMS including reference method(s); and

(h) Program of corrective action for malfunctioning CEMS.

3.2 These written procedures must be kept on site and available for inspection by the delegated authority. As described in section 5.4, whenever excessive inaccuracies occur for two consecutive quarters, you must revise the current written procedures, or modify or replace the CEMS to correct the deficiency causing the excessive inaccuracies.

4.0 Daily Data Quality Requirements and Measurement Standardization Procedures

4.1 CD Assessment. An upscale gas, used to meet a requirement in this section must be either a NIST-traceable reference gas or a gas certified by the gas vendor to ±5.0 percent accuracy.

4.1.1 CD Requirement. Consistent with 40 CFR 60.13(d) and 63.8(c), you, as source owners or operators of CEMS must check, record, and quantify the CD at two levels, using a zero gas and mid-level gas at least once daily (approximately every 24 hours). Perform the CD check in accordance with the procedure in applicable performance specification (*e.g.,* section 11.8 of PS–18 in appendix B of this part). The daily zero- and mid-level CD must not exceed two times the drift limits specified in the applicable performance specification (*e.g.,* section 13.2 of PS–18 in appendix B to this part.)

4.1.2 Recording Requirement for CD Corrective action. Corrective actions taken to bring a CEMS back in control after exceeding a CD limit must be recorded and reported with the associated CEMS data. Reporting corrective action must include the unadjusted concentration measured prior to resetting the calibration and the adjusted value after resetting the calibration to bring the CEMS back into control.

4.1.3 Dynamic Spiking Option for Mid-level CD. For extractive CEMS, you have the option to conduct a daily dynamic spiking procedure found in section 11.8.8 of PS–18 of appendix B of this part in lieu of the daily mid-level CD check. If this option is selected, the daily zero CD check is still required.

4.1.4 Out of Control Criteria for Excessive CD. As specified in § 63.8(c)(7)(i)(A), a CEMS is out of control if the zero or mid-level CD exceeds two times the applicable CD specification in the applicable PS or in the relevant standard. When a CEMS is out of control, you as owner or operator of the affected source must take the necessary corrective actions and repeat the tests that caused the system to go out of control (in this case, the failed CD check) until the applicable performance requirements are met.

4.1.5 Additional Quality Assurance for Data above Span. This procedure must be used when required by an applicable regulation and may be used when significant data above span is being collected.

4.1.5.1 Any time the average measured concentration of HCl exceeds 150 percent of the span value for greater than two hours, conduct the following 'above span' CEMS response check.

4.1.5.1.1 Within a period of 24 hours (before or after) of the 'above span' period, introduce a higher, 'above span' HCl reference gas standard to the CEMS. Use 'above span' reference gas that meets the requirements of section 7.0 of PS–18 and target a concentration level between 75 and 125 percent of the highest hourly concentration measured during the period of measurements above span.

4.1.5.1.2 Introduce the reference gas at the probe for extractive CEMS or for IP–CEMS as an equivalent path length corrected concentration in the instrument calibration cell.

4.1.5.1.3 At no time may the 'above span' concentration exceed the analyzer full-scale range.

4.1.5.2 Record and report the results of this procedure as you would for a daily calibration. The 'above span' response check is successful if the value measured by the CEMS is within 20 percent of the certified value of the reference gas.

4.1.5.3 If the 'above span' response check is conducted during the period when measured emissions are above span and there is a failure to collect at least one data point in an hour due to the response check duration, then determine the emissions average for that missed hour as the average of hourly averages for the hour preceding the missed hour and the hour following the missed hour.

4.1.5.4 In the event that the 'above span' response check is not successful (*i.e.,* the CEMS measured value is not within 20 percent of the certified value of the reference gas), then you must normalize the one-hour average stack gas values measured above the span during the 24-hour period preceding or following the 'above span' response check for reporting based on the CEMS response to the reference gas as shown in Eq. 6–1:

$$\text{Normalized stack gas result} = \frac{\text{Certified reference gas value}}{\text{Measured value of reference gas}} \times \text{Measured stack gas result} \qquad \text{Eq.6-1}$$

4.2 Beam Intensity Requirement for HCl IP–CEMS.

4.2.1 Beam Intensity Measurement. If you use a HCl IP–CEMS, you must quantify and record the beam intensity of the IP–CEMS in appropriate units at least once daily (approximately 24 hours apart) according to manufacturer's specifications and procedures.

4.2.2 Out of Control Criteria for Excessive Beam Intensity Loss. If the beam intensity falls below the level established for the operation range determined following the procedures in section 11.2 of PS–18 of this part, then your CEMS is out-of-control. This quality check is independent of whether the CEMS daily CD is acceptable. If your CEMS is out-of-control, take necessary corrective action. You have the option to repeat the beam intensity test procedures in section 11.2 of PS–18 to expand the acceptable range of acceptable beam intensity. Following corrective action, repeat the beam intensity check.

4.3 Out Of Control Period Duration for Daily Assessments. The beginning of the out-of-control period is the hour in which the owner or operator conducts a daily performance check (*e.g.,* calibration drift or beam intensity check) that indicates an exceedance of the performance requirements established under this procedure. The end of the out-of-control period is the completion of daily assessment of the same type following corrective actions, which shows that the applicable performance requirements have been met.

4.4 CEMS Data Status During Out-of-Control Period. During the period the CEMS is out-of-control, the CEMS data may not be used in calculating compliance with an emissions limit nor be counted towards meeting minimum data availability as required and described in the applicable regulation or permit.

5.0 Data Accuracy Assessment

You must audit your CEMS for the accuracy of HCl measurement on a regular basis at the frequency described in this section, unless otherwise specified in an applicable regulation or permit. Quarterly audits are performed at least once each calendar quarter. Successive quarterly audits, to the extent practicable, shall occur no closer than 2 months apart. Annual audits are performed at least once every four consecutive calendar quarters.

5.1 Temperature and Pressure Accuracy Assessment for IP CEMS.

5.1.1 Stack or source gas temperature measurement audits for HCl IP–CEMS must be conducted and recorded at least annually in accordance with the procedure described in section 11.3 of PS–18 in appendix B to this part. As an alternative, temperature measurement devices may be replaced with certified instruments on an annual basis. Units removed from service may be bench tested against an NIST traceable sensor and reused during subsequent years. Any measurement instrument or device that is used to conduct ongoing verification of temperature measurement must have an accuracy that is traceable to NIST.

5.1.2 Stack or source gas pressure measurement audits for HCl IP–CEMS must be conducted and recorded at least annually in accordance with the procedure described in section 11.4 of PS–18 in appendix B of this part. As an alternative, pressure measurement devices may be replaced with certified instruments on an annual basis. Units removed from service may be bench tested against an NIST traceable sensor and reused during subsequent years. Any measurement instrument or device that is used to conduct ongoing verification of pressure measurement must have an accuracy that is traceable to NIST.

5.1.3 Out of Control Criteria for Excessive Parameter Verification Inaccuracy. If the temperature or pressure verification audit exceeds the criteria in sections 5.3.4.5 and 5.3.4.6, respectively, the CEMS is out-of-control. If the CEMS is out-of-control, take necessary corrective action to eliminate the problem. Following corrective action, you must repeat the failed verification audit until the temperature or pressure measurement device is operating within the applicable specifications, at which point the out-of-control period ends.

5.2 Concentration Accuracy Auditing Requirements. Unless otherwise specified in an applicable rule or permit, you must audit the HCl measurement accuracy of each CEMS at least once each calendar quarter, except in the case where the affected facility is off-line (does not operate). In that case, the audit must be performed as soon as is practicable in the quarter in which the unit recommences operation. Successive quarterly audits must, to the extent practicable, be performed no less than 2 months apart. The accuracy audits shall be conducted as follows:

5.2.1 Relative Accuracy Test Audit. A RATA must be conducted at least once every four calendar quarters, except as otherwise noted in sections 5.2.5 or 5.5 of this procedure. Perform the RATA as described in section 11.9 of PS–18 in appendix B to this part. If the HCl concentration measured by the RM during a RATA (in ppmv) is less than or equal to 20 percent of the concentration equivalent to the applicable emission standard, you must perform a Cylinder Gas Audit (CGA) or a Dynamic Spike Audit (DSA) for at least one subsequent (one of the following three) quarterly accuracy audits.

5.2.2 Quarterly Relative Accuracy Audit (RAA). A quarterly RAA may be conducted as an option to conducting a RATA in three of four calendar quarters, but in no more than three quarters in succession. To conduct an RAA, follow the test procedures in section 11.9 of PS–18 in appendix B to this part, except that only three test runs are required. The difference between the mean of the RM values and the mean of the CEMS responses relative to the mean of the RM values (or alternatively the emission standard) is used to assess the accuracy of the CEMS. Calculate the RAA results as described in section 6.2. As an alternative to an RAA, a cylinder gas audit or a dynamic spiking audit may be conducted.

5.2.3 Cylinder Gas Audit. A quarterly CGA may be conducted as an option to conducting a RATA in three of four calendar quarters, but in no more than three consecutive quarters. To perform a CGA, challenge the CEMS with a zero-level and two upscale level audit gases of known concentrations within the following ranges:

Audit point	Audit range
1 (Mid-Level)	50 to 60% of span value.
2 (High-Level) ...	80 to 100% of span value.

5.2.3.1 Inject each of the three audit gases (zero and two upscale) three times each for a total of nine injections. Inject the gases in such a manner that the entire CEMS is challenged. Do not inject the same gas concentration twice in succession.

5.2.3.2 Use HCl audit gases that meet the requirements of section 7 of PS–18 in appendix B to this part.

5.2.3.3 Calculate results as described in section 6.3.

5.2.4 Dynamic Spiking Audit. For extractive CEMS, a quarterly DSA may be conducted as an option to conducting a RATA in three of four calendar quarters, but in no more than three quarters in succession.

5.2.4.1 To conduct a DSA, you must challenge the entire HCl CEMS with a zero gas in accordance with the procedure in section 11.8 of PS–18 in appendix B of this part. You must also conduct the DS procedure as described in appendix A to PS–18 of appendix B to this part. You must conduct three spike injections with each of two upscale level audit gases. The upscale level gases must meet the requirements of section 7 of PS–18 in appendix B to this part and must be chosen to yield concentrations at the analyzer of 50 to 60 percent of span and 80 to 100 percent of span. Do not inject the same gas concentration twice in succession.

5.2.4.2 Calculate results as described in section 6.4. You must calculate the dynamic spiking error (DSE) for each of the two upscale audit gases using the combination of Equation A5 and A6 in appendix A to PS–18 in appendix B to this part to determine CEMS accuracy.

5.2.5 Other Alternative Quarterly Audits. Other alternative audit procedures, as approved by the Administrator, may be used for three of four calendar quarters.

5.3 Out of Control Criteria for Excessive Audit Inaccuracy. If the results of the RATA, RAA, CGA, or DSA do not meet the applicable performance criteria in section 5.3.4, the CEMS is out-of-control. If the CEMS is out-of-control, take necessary corrective action to eliminate the problem. Following corrective action, the CEMS must pass a test of the same type that resulted in the out-of-control period to determine if the CEMS is operating within the specifications (*e.g.,* a RATA must always follow an out-of-control period resulting from a RATA).

5.3.1 If the audit results show the CEMS to be out-of-control, you must report both the results of the audit showing the CEMS to be out-of-control and the results of the audit following corrective action showing the CEMS to be operating within specifications.

5.3.2 Out-Of-Control Period Duration for Excessive Audit Inaccuracy. The beginning of the out-of-control period is the time corresponding to the completion of the sampling for the failed RATA, RAA, CGA or DSA. The end of the out-of-control period is the time corresponding to the completion of the sampling of the subsequent successful audit.

5.3.3 CEMS Data Status During Out-Of-Control Period. During the period the CEMS is out-of-control, the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability as required and described in the applicable regulation or permit.

5.3.4 Criteria for Excessive Quarterly and Yearly Audit Inaccuracy. Unless specified otherwise in the applicable regulation or permit, the criteria for excessive inaccuracy are:

5.3.4.1 For the RATA, the CEMS must meet the RA specifications in section 13.4 of PS–18 in appendix B to this part.

5.3.4.2 For the CGA, the accuracy must not exceed 5.0 percent of the span value at the zero gas and the mid- and high-level reference gas concentrations.

5.3.4.3 For the RAA, the RA must not exceed 20.0 percent of the RM_{avg} as calculated using Equation 6–2 in section 6.2 of this procedure whether calculated in units of HCl concentration or in units of the emission standard. In cases where the RA is calculated on a concentration (ppmv) basis, if the average HCl concentration measured by the RM during the test is less than 75 percent of the HCl concentration equivalent to the applicable standard, you may substitute the equivalent emission standard value (in ppmvw) in the denominator of Equation 6–2 in the place of RM_{avg} and the result of this alternative calculation of RA must not exceed 15.0 percent.

5.3.4.4 For DSA, the accuracy must not exceed 5.0 percent of the span value at the zero gas and the mid- and high-level reference gas concentrations or 20.0 percent of the applicable emission standard, whichever is greater.

5.3.4.5 For the gas temperature measurement audit, the CEMS must satisfy the requirements in section 13.7 in PS–18 of appendix B to this part.

5.3.4.6 For the gas pressure measurement audit, the CEMS must satisfy the requirements in section 13.8 in PS–18 of appendix B to this part.

5.4 Criteria for Acceptable QC Procedures. Repeated excessive inaccuracies (*i.e.,* out-of-control conditions resulting from the quarterly or yearly audits) indicate that the QC procedures are inadequate or that the CEMS is incapable of providing quality data. Therefore, whenever excessive inaccuracies occur for two consecutive quarters, you must revise the QC procedures (see section 3.0) or modify or replace the CEMS.

5.5 Criteria for Optional QA Test Frequency. If all the quality criteria are met in sections 4 and 5 of this procedure, the CEMS is in-control.

5.5.1 Unless otherwise specified in an applicable rule or permit, if the CEMS is in-control and if your source emits ≤75 percent of the HCl emission limit for each averaging period as specified in the relevant standard for eight consecutive quarters that include a minimum of two RATAs, you may revise your auditing procedures to use CGA, RAA or DSA each quarter for seven subsequent quarters following a RATA.

5.5.2 You must perform at least one RATA that meets the acceptance criteria every 2 years.

5.5.3 If you fail a RATA, RAA, CGA, or DSA, then the audit schedule in section 5.2 must be followed until the audit results meet the criteria in section 5.3.4 to start requalifying for the optional QA test frequency in section 5.5.

6.0 Calculations for CEMS Data Accuracy

6.1 RATA RA Calculation. Follow Equations 9 through 14 in section 12 of PS–18 in appendix B to this part to calculate the RA for the RATA. The RATA must be calculated either in units of the applicable emission standard or in concentration units (ppmv).

6.2 RAA Accuracy Calculation. Use Equation 6–2 to calculate the accuracy for the RAA. The RA may be calculated in concentration units (ppmv) or in the units of the applicable emission standard.

$$RA = \frac{[MN_{avg} - RM_{avg}]}{RM_{avg}} * 100 \text{ Eq.} \qquad \text{Eq. 6-2}$$

Where:

RA = Accuracy of the CEMS (percent)

MN_{avg} = Average measured CEMS response during the audit in units of applicable standard or appropriate concentration.

RM_{avg} = Average reference method value in units of applicable standard or appropriate concentration.

6.3 CGA Accuracy Calculation. For each gas concentration, determine the average of the three CEMS responses and subtract the average response from the audit gas value. For extractive CEMS, calculate the ME at each gas level using Equation 3A in section 12.3 of PS–18 in appendix B to this part. For IP–CEMS, calculate the ME at each gas level using Equation 6A in section 12.4.3 of PS–18 in appendix B to this part.

6.4 DSA Accuracy Calculation. DSA accuracy is calculated as a percent of span. To calculate the DSA accuracy for each upscale spike concentration, first calculate the DSE using Equation A5 in appendix A of PS–18 in appendix B to this part. Then use Equation 6–3 to calculate the average DSA accuracy for each upscale spike concentration. To calculate DSA accuracy at the zero level, use equation 3A in section 12.3 of PS–18 in appendix B to this part.

$$DSA\ Accuracy = \frac{\Sigma_1^3 \left[\frac{|DSE_i|}{S} \right]}{3} * 100 \qquad \text{Eq. 6-3}$$

7.0 Reporting Requirements

At the reporting interval specified in the applicable regulation or permit, report for each CEMS the quarterly and annual accuracy audit results from section 6 and the daily assessment results from section 4. Unless otherwise specified in the applicable regulation or permit, include all data sheets, calculations, CEMS data records (*i.e.,* charts, records of CEMS responses), reference gas certifications and reference method results necessary to confirm that the performance of the CEMS met the performance specifications.

7.1 Unless otherwise specified in the applicable regulations or permit, report the daily assessments (CD and beam intensity) and accuracy audit information at the interval for emissions reporting required under the applicable regulations or permits.

7.1.1 At a minimum, the daily assessments and accuracy audit information reporting must contain the following information:

a. Company name and address.

b. Identification and location of monitors in the CEMS.

c. Manufacturer and model number of each monitor in the CEMS.

d. Assessment of CEMS data accuracy and date of assessment as determined by a RATA, RAA, CGA or DSA described in section 5 including:

i. The RA for the RATA;

ii. The accuracy for the CGA, RAA, or DSA;

iiii. Temperature and pressure sensor audit results for IP–CEMS;

iv. The RM results, the reference gas certified values;

v. The CEMS responses;

vi. The calculation results as defined in section 6; and

vii. Results from the performance audit samples described in section 5 and the applicable RMs.

e. Summary of all out-of-control periods including corrective actions taken when CEMS was determined out-of-control, as described in sections 4 and 5.

7.1.2 If the accuracy audit results show the CEMS to be out-of-control, you must report both the audit results showing the CEMS to be out-of-control and the results of the audit following corrective action showing the CEMS to be operating within specifications.

8.0 Bibliography

1. EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, U.S. Environmental Protection Agency office of Research and Development, EPA/600/R–12/531, May 2012.

2. Method 205, ''Verification of Gas Dilution Systems for Field Instrument Calibrations,'' 40 CFR part 51, appendix M.

9.0 Tables, Diagrams, Flowcharts—[Reserved]

[FR Doc. 2015–16385 Filed 7–6–15; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

45 CFR Part 155

[CMS–9944–F2]

RIN 0938–AS19

Patient Protection and Affordable Care Act; HHS Notice of Benefit and Payment Parameters for 2016; Correcting Amendment

AGENCY: Centers for Medicare & Medicaid Services (CMS), HHS.

ACTION: Final rule; correcting amendment.

SUMMARY: This document corrects a technical error that appeared in the final rule published in the February 27, 2015 **Federal Register** (80 FR 10749) entitled ''Patient Protection and Affordable Care Act; HHS Notice of Benefit and Payment Parameters for 2016.''

DATES: *Effective Date:* This correction document is effective July 7, 2015.

Application Date: The correction is applicable as of April 28, 2015.

FOR FURTHER INFORMATION CONTACT:

Jeff Wu, (301) 492–4305.
Krutika Amin, (301) 492–5153.
Lindsey Murtagh, 301–492–4106.
Rachel Arguello, 301–492–4263.

SUPPLEMENTARY INFORMATION:

I. Background

In FR Doc. 2015–03751 (80 FR 10749 through 10877), the final rule entitled

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2013–0696; FRL–9929–25–OAR]

RIN 2060–AR81

Performance Specification 18—Performance Specifications and Test Procedures for Hydrogen Chloride Continuous Emission Monitoring Systems at Stationary Sources

Correction

In rule document 2015–16385, appearing on pages 38628 through 38652 in the issue of Tuesday, July 7, 2015, make the following correction:

On page 38646, in the first column, in the last paragraph, in the sixth line, ''+5'' should read ''±5''.

[FR Doc. C1–2015–16385 Filed 7–16–15; 8:45 am]

BILLING CODE 1505–01–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2015–0396; FRL–9929–95]

Thiabendazole; Pesticide Tolerances for Emergency Exemptions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes a time-limited tolerance for residues of thiabendazole in or on succulent shelled peas.

This action is associated with the utilization of a crisis exemption under the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) authorizing use of the pesticide as a seed treatment on succulent pea seeds. This regulation establishes a maximum permissible level for residues of thiabendazole in or on this commodity. The time-limited tolerance expires on December 31, 2018.

DATES: This regulation is effective July 17, 2015. Objections and requests for hearings must be received on or before September 15, 2015, and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The docket for this action, identified by docket identification (ID) number EPA–HQ–OPP–2015–0396, is available at *http://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW., Washington, DC 20460–0001. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OPP Docket is (703) 305–5805. Please review the visitor instructions and additional information about the docket available at *http://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Susan Lewis, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; main telephone number: (703) 305–7090; email address: *RDFRNotices@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

B. How can I get electronic access to other related information?

You may access a frequently updated electronic version of 40 CFR part 180 through the Government Printing Office's e-CFR site at *http://www.ecfr.gov/cgi-bin/text-idx?&c=ecfr&tpl=/ecfrbrowse/Title40/40tab_02.tpl.*

C. How can I file an objection or hearing request?

Under section 408(g) of the Federal Food, Drug, and Cosmetic Act (FFDCA), 21 U.S.C. 346a, any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2015–0396 in the subject line on the first page of your submission. All objections and requests for a hearing must be in writing, and must be received by the Hearing Clerk on or before September 15, 2015. Addresses for mail and hand delivery of objections and hearing requests are provided in 40 CFR 178.25(b).

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing (excluding any Confidential Business Information (CBI)) for inclusion in the public docket. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit the non-CBI copy of your objection or hearing request, identified by docket ID number EPA–HQ–OPP–2015–0396, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be CBI or other information whose disclosure is restricted by statute.
- *Mail:* OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001.
- *Hand Delivery:* To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at *http://www.epa.gov/dockets/contacts.html.*

Additional instructions on commenting or visiting the docket, along with more information about dockets generally, is available at *http://www.epa.gov/dockets.*

II. Background and Statutory Findings

EPA, on its own initiative, in accordance with FFDCA sections 408(e) and 408(l)(6), 21 U.S.C. 346a(e) and 346a(1)(6), is establishing a time-limited tolerance for the combined residues of the fungicide thiabendazole (2-(4-thiazolyl)benzimidazole) and its metabolite benzimidazole (free and conjugated) in or on pea, succulent shelled at 0.02 parts per million (ppm). This time-limited tolerance expires on December 31, 2018.

Section 408(l)(6) of FFDCA requires EPA to establish a time-limited tolerance or exemption from the requirement for a tolerance for pesticide chemical residues in food that will result from the use of a pesticide under an emergency exemption granted by EPA under FIFRA section 18. Such tolerances can be established without providing notice or period for public comment. EPA does not intend for its actions on FIFRA section 18 related

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Part VI

Environmental Protection Agency

40 CFR Part 60 and 63
National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60 and 63

[EPA–HQ–OAR–2011–0817; FRL–9927–62–OAR]

RIN 2060–AQ93

National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final amendments.

SUMMARY: This action finalizes amendments to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants. On February 12, 2013, the Environmental Protection Agency (EPA) finalized amendments to the NESHAP and the new source performance standards (NSPS) for the Portland cement industry. Subsequently, the EPA became aware of certain minor technical errors in those amendments, and thus issued a proposal to correct these errors on November 19, 2014 (79 FR 68821). The EPA received 3 comments on the proposal. In response to the comments received and to complete technical corrections, the EPA is now issuing final amendments. In addition, consistent with the U.S. Court of Appeals to the DC Circuit's vacatur of the affirmative defense provisions in the final rule, this action removes those provisions. These amendments do not affect the pollution reduction or costs associated with these standards.

DATES: This final rule is effective on July 27, 2015.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2011–0817. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, 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. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the EPA's Docket Center, Public Reading Room, EPA WJC West Building, Room Number 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This docket facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Sharon Nizich, Sector Policies and Programs Division (D243–04), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–2825; facsimile number: (919) 541–5450; email address: *nizich.sharon@epa.gov.* For information about the applicability of the NESHAP or NSPS, contact Mr. Patrick Yellin, Monitoring, Assistance and Media Programs Division (2227A), Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, Washington, DC 20460; telephone number (202) 564–2970; email address *yellin.patrick@epa.gov.*

SUPPLEMENTARY INFORMATION:

Organization of This Document. The information presented in this preamble is organized as follows:

I. Preamble Acronyms and Abbreviations

Several acronyms and terms are included in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined here:

APCD	air pollution control devices
CAA	Clean Air Act
CEMS	continuous emission monitoring systems
CFR	Code of Federal Regulations
EPA	Environmental Protection Agency
FR	Federal Register
Hg	mercury
HCl	hydrogen chloride
NAICS	North American Industry Classification System
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NSPS	new source performance standards
NTTAA	National Technology Transfer and Advancement Act
oHAP	Non-dioxin organic hazardous air pollutants
OMB	Office of Management and Budget
PM	particulate matter
ppm(v)(d,w)	parts per million (by volume) (dry,wet)
SO_2	Sulfur Dioxide
THC	total hydrocarbons
TTN	Technology Transfer Network
UMRA	Unfunded Mandates Reform Act
WWW	World Wide Web

II. General Information

A. Executive Summary

1. Purpose of This Regulatory Action

The purpose of this action is to finalize amendments to the 40 CFR part 60, and part 63, subparts F and LLL, respectively. In 2010, the EPA established the NESHAP for the Portland Cement source category. (75 FR 54970, September 9, 2010). Specifically, the EPA established emission standards for mercury (Hg), hydrogen chloride (HCl), total hydrocarbons (THC) (or in the alternative, organic hazardous air pollutants (oHAP)), and particulate matter (PM). These standards, established pursuant to section 112(d) of the Clean Air Act (CAA), reflected performance of maximum available control technology. Following court remand, *Portland Cement Ass'n* v. *EPA,* 665 F. 3d 177 (D.C. Cir. 2011), the EPA amended some of these standards in 2013, and established a new compliance date of September 9, 2015, for the amended standards. (78 FR 10006, Feb. 12, 2013). All of these actions were upheld by the U.S. Court of Appeals for the District of Columbia Circuit. *Natural Resources Defense Council* v. *EPA,* 749 F. 3d 1055 (D.C. Cir. 2014). The Court, however, vacated a provision of the rule establishing an affirmative defense when violations of the standards occurred because of malfunctions. 749 F. 3d at 1063–64. In light of the Court's vacatur, the regulatory provisions establishing the affirmative defense are null and void. Thus, the EPA is removing the affirmative defense regulatory text (40 CFR 63.1344) as part of this final technical corrections rule.

The EPA also adopted standards of performance for new Portland cement sources as part of the same regulatory action establishing the 2010 NESHAP. (75 FR 54970, Sept. 9, 2010) and amended those standards at the same time of the NESHAP amendments (see 78 FR 10006) (see also *Portland Cement Ass'n* v. *EPA,* 665 F. 3d at 190–92 (upholding these standards)). The EPA is finalizing certain technical changes to these NSPS as part of this action.

B. Does this reconsideration action apply to me?

Categories and entities potentially regulated by this final rule include:

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS NESHAP AND NSPS FINAL ACTION

Category	NAICS code [a]	Examples of regulated entities
Industry	327310	Portland cement manufacturing plants.
Federal government		Not affected.
State/local/tribal government		Portland cement manufacturing plants.

[a] North American Industry Classification System.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your facility will be regulated by this action, you should examine the applicability criteria in 40 CFR 60.60 (subpart F) or in 40 CFR 63.1340 (subpart LLL). If you have any questions regarding the applicability of this final action to a particular entity, contact the appropriate person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

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 through the EPA's Technology Transfer Network (TTN) Web site, a forum for information and technology exchange in various areas of air pollution control. Following signature by the EPA Administrator, the EPA will post a copy of this final action at *http://www.epa.gov/airquality/cement.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the proposal and key technical documents at this same Web site.

D. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final action is available only by filing a petition for review in the court by September 25, 2015. Under section 307(b)(2) of the CAA, the requirements established by the final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA 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 should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, WJC Building, 1200 Pennsylvania Ave. NW., Mail Code 1101A, 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), U.S. EPA, 1200 Pennsylvania Ave. NW., Mail Code 2344A, Washington, DC 20460.

III. Summary of Final Amendments

A. Corrections and Clarifications

The EPA is finalizing certain clarifying changes and corrections to the 2013 final rule. Specifically, these amendments will: (1) Clarify the definition of rolling average, operating day and run average; (2) restore the table of emission limits which apply until the September 9, 2015, compliance date; (3) correct equation 8 regarding sources with an alkali bypass or inline coal mill that include a separate stack; (4) provide a scaling alternative for sources that have a wet scrubber, tray tower or dry scrubber relative to the HCl compliance demonstration; (5) add a temperature parameter to the startup and shutdown requirements; (6) clarify language related to span values for both Hg and HCl measurements; and (7) correct inadvertent typographical errors. The EPA is also finalizing corrections to certain inadvertent inconsistencies in the final rule regulatory text, such as correction of the compliance date for new sources and correction to the compliance date regarding monitoring and recordkeeping requirements.

In both the NSPS and the NESHAP, we are finalizing language to clarify the existing definitions of Operating Day, Rolling Average and Run Average to promote consistent and clear monitoring data recording and emissions reporting. The clarifications below are in response to industry questions and are not intended to change the meaning of the final rule. In the final amendments, we clarify that ''Operating Day'' is any 24-hour period where clinker is produced. This clarification is necessary to specify that during any day with both operations and emissions, an emissions value or an average of emissions values representing those operations is included in the 30-day rolling average calculation. We also clarify that ''Rolling Average'' means a weighted average of all monitoring data collected during a specified time period divided by all production of clinker during those same hours of operation, and, where applicable, a 30-day rolling average is comprised of the average of all the hourly average concentrations over the previous 30 operating days. This clarification is necessary to specify the way a long-term rolling average value is calculated such that different facilities are not using different approaches to demonstrate compliance with the rule. In addition, we clarify that ''Run Average'' means the average of the recorded parameter values, not the 1-minute parameter values, for a run.

We are amending 40 CFR 63.1349(b)(8)(vii) to include a provision describing performance testing requirements when a source demonstrates compliance with the emissions standard using a continuous emissions monitoring system (CEMS) for sulfur dioxide (SO_2) measurement and reporting.

We are adding a scaling alternative whereby if a source uses a wet scrubber, tray tower or dry scrubber, and where the test run average of the three HCl compliance tests demonstrates compliance below 2.25 parts per million by volume (ppmv) (which is 75 percent of the HCl emission limit), the source may calculate an operating limit by establishing a relationship of the average SO_2 CEMS signal to the HCl concentration (corrected to 7 percent oxygen). The operating limit would be established at a point where the SO_2 CEMS indicates the source would be at 2.25 ppmv. Since the 2.25 ppmv is below the actual limit of 3.0 ppmv, the source will continue to demonstrate compliance with the HCl standard. Given the fact that SO_2 controls preferentially remove HCl, an increase in SO_2 emissions would not indicate an increase in HCl emissions as long as some SO_2 emissions reductions are occurring. Adding this compliance flexibility should not result in any increase in HCl emissions.

We are also amending, under 40 CFR 63.1346(g)(3), language related to the use of air pollution control devices (APCD). We had proposed that all hazardous APCD be operating by the time the temperature to the APCD reaches 300 °F. However, during the comment period, the EPA received further clarification on the temperature parameter. Commenters noted that the temperature threshold during startup need only apply to injection systems and not all APCD, and that the temperature reading should occur at the PM control device inlet. Commenters also noted that as soon as fuel is shut off during shutdown, gas flows can decrease to the point where activated carbon and hydrated lime being injected can fall out of the stream and accumulate in the duct work due to reduced gas flows. In addition, lime affected by water vapor condensation present during startup and shutdown conditions will cause the lime to harden and reduce the efficiency for dust removal.[1] Because of the injection system operating restrictions with startup and shutdown, revision of the startup and shutdown work practice is amended in the final rule to clarify that the injection system may be shut off when kiln feed is shut off. In addition to this revision regarding injection systems, clarification that all control devices for HAP must be operating during startup and shutdown has been included in the regulatory text.

We are also finalizing measurement span criteria for HCl CEMS to include better quality assurance/quality control (QA/QC) for measurements of elevated HCl emissions that may result from ''mill off'' operations. This slight increase in measurement span (from 5 parts per million (ppm) to 10 ppm) provides for an improved balance between accurately quantifying measurements at low emissions levels (the majority of operating time) and improving QA/QC for brief periods of elevated emissions observed during ''mill off'' operation (the majority of HCl mass emissions).

In these final amendments, we remove 40 CFR 60.64(c)(2), which applied when sources did not have valid 15-minute CEMS data. This provision allowed for inclusion of the average emission rate from the previous hour for which data were available. This provision was inadvertently added to the final rule, but this substitution is not an allowable action.

We are also revising 40 CFR 63.1350(o) (Alternative Monitoring Requirements Approval), because language in this section, which does not allow an operator to apply for alternative THC monitoring, is now obsolete. There is now alternative monitoring allowed in 40 CFR 63.1350(j) due to the 2013 final rule (see 78 FR 10015). A source that emits a high amount of THC due to methane emissions, for example, can follow the alternative oHAP monitoring requirements. For any other reason that an alternative THC monitoring protocol is warranted, we allow the source to submit an application to the Administrator subject to the provisions of 40 CFR 63.1350(o)(1) through (6).

B. Affirmative Defense

The EPA is removing a regulatory affirmative defense provision from the rule. As explained above, removal of the affirmative defense merely corrects the regulation to reflect that the provisions have no legal effect in light of the court vacatur of the affirmative defense provisions in the Portland Cement NESHAP rule. *NRDC* v. *EPA,* 749 F. 3d at 1063–64 (D.C. Cir. 2014).

IV. Summary of Changes Since Proposal

Section III summarized the amendments to the 2013 NSPS and NESHAP rules that the EPA is finalizing in this rule. Due to public comments, minor changes to the proposed regulatory text have been included in the final rule. These minor changes are discussed in the response to comment document that can be found in the docket. We believe that these minor changes sufficiently address concerns expressed by commenters and improve the clarity of the rule while improving or preserving public health and environmental protection required under the CAA.

V. Summary of Comments and Responses

We proposed amendments to the 2013 NSPS and NESHAP rules on November 19, 2014 (see 79 FR 68821). We received 3 comment letters, and consequently made some additional corrections in response to these comments. Comments and responses on these amendments are summarized in the response to comments document found in the docket. There were no significant comments received on the proposed technical amendments. A list of typographical errors we proposed to correct, and are now finalizing, can be found in the proposed rule at 79 FR 68824. For clarity, we are including a table of additional typographical corrections found by the commenters on the proposed rule.

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[1] These issues are further discussed in the docket, via communication with John Holmes dated September 24, 2014.

TABLE 2—MISCELLANEOUS FINAL TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART LLL

Section of subpart LLL	Description of correction
40 CFR 63.1347(a)(1)	Referred rule numbers have been changed from Section 63.1343 through 63.1348, to Sections 63.1343, 1345 and 1346.
40 CFR 63.1349(b)(1)(iii)	Reference to procedures in (a)(1)(iii)(A) through (D) is changed to (b)1(iii)(A) through (D).
40 CFR 63.1349(b)(1)(iii)(A)(4)	Reference in this section is changed from (a)(1)(iii)(A)(1) through (3) to (b)(1)(iii)(A)(1) through (3).
40 CFR 63.1349(b)(3)(iv)	Reference in this section is changed from 63.1344(b) to 63.1346(b).
40 CFR 63.1349(b)(7)(ii)	Reference in this section is changed from (a)(7)(vii) and (viii)) to (b)(7)(viii) through (ix).
40 CFR 63.1349(b)(7)(vii)	Reference in this section is changed from (a)(7)(vii) and (viii) to (b)(7)(viii) through (ix).
40 CFR 63.1349(b)(7)(viii)	Reference in this section is changed from (a)(7)(vii)(A) and (B) to (b)(7)(viii)(A) and (B).
Equation 13	The variable Y listed in units of ppmv is changed to ppmvd.
Equation 14	Variable Y_1 is listed but is not in equation and has been removed.
40 CFR 63.1349(b)(8)(viii)	Reference to Equation 18 has been changed to reference to Equation 21.
40 CFR 63.1349(c)	A range for performance testing from 29–31 months for 30 month tests and 11–13 months for annual tests has been added.
40 CFR 63.1350(k) and (l)	Clarifications on calibration and span checks have been added. Reference to Performance Specification 18 added.
40 CFR 63.1350(n)(4)	Reference in this section is changed from (n)(1) to (n)(2).
40 CFR 63.1355(d)	A requirement to keep annual records of cement kiln dust is obsolete due to the 2013 final amendment requirements of continuous monitoring, so this provision has been removed.
Table 1 to Subpart LLL of Part 63—Applicability of General Provisions	Remove reference to 63.10(e)(3)(vii) and (viii) since they were superseded by 63.1354(b)(10).

The EPA is also finalizing corrections and clarifications to the 2013 NESHAP and NSPS rules, including typographical and grammatical errors, as well as incorrect dates and cross-references. Details of the specific changes we are finalizing to the regulatory text may be found above in the table of corrections, and also in the response to comment document found in the docket for this action.

VI. Impacts of These Final Amendments

The EPA has determined that owners and operators of affected facilities would choose to install and operate the same or similar air pollution control technologies under this action as they would have installed to comply with the previously finalized standards. We project that these amendments will result in no significant change in costs, emission reductions or benefits. Even if there were changes in costs for the affected facilities, such changes would likely be small relative to both the overall costs of the individual projects and the overall costs and benefits of the final rule. Since we believe that owners and operators would put on the same controls for this revised final rule that they would have for the 2013 rule, there should not be any incremental costs related to this final rule.

A. What are the air impacts?

We believe that owners and operators of affected facilities will not revise their control technology implementation plans as a result of these final technical corrections. Accordingly, we believe that this final rule will not result in significant changes in emissions of any regulated pollutants.

B. What are the energy impacts?

This final rule is not anticipated to have an effect on the supply, distribution or use of energy. As previously stated, we believe that owners and operators of affected facilities would install the same or similar control technologies as they would have installed to comply with the previously finalized standards.

C. What are the compliance costs?

We believe there will be no significant change in compliance costs as a result of this final rule because owners and operators of affected facilities would install the same or similar control technologies as they would have installed to comply with the previously finalized standards.

D. What are the economic and employment impacts?

Because we expect that owners and operators of affected facilities would install the same or similar control technologies under this action as they would have installed to comply with the previously finalized standards, we do not anticipate that this final rule will result in significant changes in emissions, energy impacts, costs, benefits or economic impacts. Likewise, we believe this rule will not have any impacts on the price of electricity, employment or labor markets, or the U.S. economy.

E. What are the benefits of the final standards?

As previously stated, the EPA anticipates the Portland cement industry will not incur significant compliance costs or savings as a result of this action and we do not anticipate any significant emission changes resulting from these amendments to the rule. Therefore, there are no direct monetized benefits or disbenefits associated with this final rule.

VII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.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 not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the PRA. The OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0416 for the NESHAP; there are no additional recordkeeping and reporting requirements for the NSPS. This action does not change the information collection requirements previously finalized and, as a result, does not impose any additional information collection burden on industry. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. 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 impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. The EPA has determined that none of the small entities subject to this rule will experience a significant impact because this action imposes no additional compliance costs on owners or operators of affected sources. We have therefore concluded that this action will have no net regulatory burden for all directly regulated small entities.

D. Unfunded Mandates Reform Act of 1995 (UMRA)

This action does not contain any unfunded mandate 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.

E. 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.

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

This action does not have tribal implications as specified in Executive Order 13175. It will not have substantial direct effect on tribal governments, on the relationship between the federal government and Indian tribes or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

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

This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children.

This action does not add to or relieve affected sources from any requirements, and therefore has no impacts; thus, health and risk assessments were not conducted.

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

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

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations because it does not affect the level of protection provided to human health or the environment. The basis for this determination is that this action is a reconsideration of existing requirements and imposes no new impacts or costs.

K. Congressional Review Act (CRA)

This action is subject to the 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

40 CFR Part 60

Administrative practice and procedure, Air pollution control, Environmental protection, Intergovernmental relations, Reporting and recordkeeping.

40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: July 1, 2015.

Gina McCarthy,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended 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. 7411.

Subpart F—[Amended]

■ 2. Section 60.61 is amended by revising paragraph (f) and adding paragraphs (g) and (h) to read as follows:

§ 60.61 Definitions.

* * * * *

(f) *Operating day* means a 24-hour period beginning at 12:00 midnight during which the kiln produces clinker at any time. For calculating 30 day rolling average emissions, an *operating day* does not include the hours of operation during startup or shutdown.

(g) *Rolling average* means the weighted average of all data, meeting QA/QC requirements or otherwise normalized, collected during the applicable averaging period. The period of a rolling average stipulates the frequency of data averaging and reporting. To demonstrate compliance with an operating parameter a 30-day rolling average period requires calculation of a new average value each operating day and shall include the average of all the hourly averages of the specific operating parameter. For demonstration of compliance with an emissions limit based on pollutant concentration, a 30-day rolling average is comprised of the average of all the hourly average concentrations over the previous 30 operating days. For demonstration of compliance with an emissions limit based on lbs-pollutant per production unit, the 30-day rolling average is calculated by summing the hourly mass emissions over the previous 30 operating days, then dividing that sum by the total production during the same period.

(h) *Run average* means the average of the recorded parameter values for a run.

■ 3. Section 60.62 is amended by adding paragraphs (a)(1)(i), (a)(2), (b)(1)(iii) and (iv), revising paragraph (d), and adding paragraph (e) to read as follows:

§ 60.62 Standards.

(a) * * *

(1) * * *

(i) 0.30 pounds per ton of feed (dry basis) to the kiln for kilns constructed, reconstructed, or modified after August 17, 1971 but on or before June 16, 2008.

* * * * *

(2) Exhibit greater than 20 percent opacity for kilns constructed, reconstructed, or modified after August 17, 1971 but on or before June 16, 2008, except that this opacity limit does not apply to any kiln subject to a PM limit in paragraph (a)(1) of this section that uses a PM continuous parametric monitoring system (CPMS).

* * * * *

(b) * * *

(1) * * *

(iii) 0.10 lb per ton of feed (dry basis) for clinker coolers constructed, reconstructed, or modified after August 17, 1971, but on or before June 16, 2008.

(iv) 10 percent opacity for clinker coolers constructed, reconstructed, or modified after August 17, 1971, but on or before June 16, 2008, except that this opacity limit does not apply to any clinker cooler subject to a PM limit in paragraph (b)(1) of this section that uses a PM continuous parametric monitoring system (CPMS).

* * * * *

(d) If you have an affected source subject to this subpart with a different emissions limit or requirement for the same pollutant under another regulation in title 40 of this chapter, once you are in compliance with the most stringent emissions limit or requirement, you are not subject to the less stringent requirement. Until you are in compliance with the more stringent limit, the less stringent limit continues to apply.

(e) The compliance date for all revised monitoring and recordkeeping requirements contained in this rule will be the same as listed in 63.1351(c) unless you commenced construction as of June 16, 2008, at which time the compliance date is November 8, 2010 or upon startup, whichever is later.

■ 4. Section 60.63 is amended by revising paragraphs (c)(1), (c)(2)(i) and (iii), (c)(3), (c)(4)(ii) through (iv), and (c)(5) through (8) to read as follows:

§ 60.63 Monitoring of operations.

* * * * *

(c) * * *

(1) For each kiln or clinker cooler subject to a PM emissions limit in §§ 60.62(a)1(ii) and 60.62(a)1(iii) or 60.62(b)(1)(i) and 60.62(b)(1)(ii), you must demonstrate compliance through an initial performance test. You will conduct your performance test using Method 5 or Method 5I at appendix A–3 to part 60 of this chapter. You must also monitor continuous performance through use of a PM CPMS.

(2) * * *

(i) Your PM CPMS must provide a 4–20 milliamp or digital signal output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps or the monitors digital equivalent.

(ii) * * *

(iii) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp or digital output values from the PM CPMS for the periods corresponding to the compliance test runs (*e.g.,* average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(3) Determine your operating limit as specified in paragraphs (c)(4)(i) through (c)(5) of this section. If your PM performance test demonstrates your PM emission levels to be below 75 percent of your emission limit, you will use the average PM CPMS value recorded during the PM compliance test, the milliamp or digital equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. If your PM compliance test demonstrates your PM emission levels to be at or above 75 percent of your emission limit, you will use the average PM CPMS value recorded during the PM compliance test to establish your operating limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test at least annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(4) * * *

(ii) Determine your PM CPMS instrument average in milliamps or digital equivalent and the average of your corresponding three PM compliance test runs, using equation 1.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1 , \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 1)}$$

Where:

X_1 = The PM CPMS data points for the three runs constituting the performance test,

Y_1 = The PM concentration value for the three runs constituting the performance test, and

n = The number of data points.

(iii) With your PM CPMS instrument zero expressed in milliamps or a digital value, your three run average PM CPMS milliamp or digital signal value, and your three run average PM concentration from your three PM performance test runs, determine a relationship of lb/ton-clinker per milliamp or digital signal with equation 2.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 2)}$$

Where:

R = The relative lb/ton clinker per milliamp or digital equivalent for your PM CPMS.

Y_1 = The three run average PM lb/ton clinker.

X_1 = The three run average milliamp or digital signal output from your PM CPMS.
z = The milliamp or digital equivalent of your instrument zero determined from (c)(4)(i) of this section.

(iv) Determine your source specific 30-day rolling average operating limit using the lb/ton-clinker per milliamp or digital signal value from Equation 2 above in Equation 3, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + (0.75(L)) / R \qquad \text{(Eq. 3)}$$

Where:
O_l = The operating limit for your PM CPMS on a 30-day rolling average, in milliamps or the digital equivalent.
L = Your source emission limit expressed in lb/ton clinker.
z = Your instrument zero in milliamps or a digital equivalent, determined from (1)(i).
R = The relative lb/ton-clinker per milliamp or digital equivalent, for your PM CPMS, from Equation 2.

(5) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit, you must determine your operating limit by averaging the PM CPMS milliamp or digital equivalent output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using Equation 4.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 4)}$$

Where:
X_1 = The PM CPMS data points for all runs i.
n = The number of data points.
O_h = Your site specific operating limit, in milliamps or digital equivalent.

(6) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating, and use all the PM CPMS data for calculations when the source is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps or the digital equivalent) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 5 to determine the 30 kiln operating day average.

$$\text{30kiln operating day average} = \frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 5)}$$

Where:
Hpvi = The hourly parameter value for hour i.
n = The number of valid hourly parameter values collected over the previous 30 kiln operating days.

(7) Use EPA Method 5 or Method 5I of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct at least three separate runs each while the mill is on and the mill is off under the conditions that exist when the affected source is operating at the level reasonably expected to occur. Conduct each test run to collect a minimum sample volume of 2 dscm for determining compliance with a new source limit and 1 dscm for determining compliance with an existing source limit. Calculate the time weighted average of the results from three consecutive runs to determine compliance. You need not determine the particulate matter collected in the impingers (''back half'') of the Method 5 or Method 5I particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the ''back half'' for other purposes.

(8) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (*e.g.* beta attenuation), span of the instruments primary analytical range, milliamp or digital signal value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp or digital equivalent signals corresponding to each PM compliance test run.

* * * * *

■ 5. Section 60.64 is amended by revising paragraph (c) introductory text and removing and reserving paragraph (c)(2).

The revision reads as follows:

§ 60.64 Test methods and procedures.

* * * * *

(c) Calculate and record the rolling 30 kiln operating day average emission rate daily of NO_X and SO_2 according to the procedures in paragraph (c)(1) of this section.

* * * * *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 6. The authority citation for part 63 continues to read as follows:

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

Subpart LLL—[Amended]

■ 7. Section 63.1341 is amended by revising the definitions for ''Operating day'', ''Rolling average'', and ''Run average'' to read as follows:

§ 63.1341 Definitions.

* * * * *

Operating day means any 24-hour period beginning at 12:00 midnight during which the kiln produces any amount of clinker. For calculating the 30-day rolling average emissions, kiln operating days do not include the hours of operation during startup or shutdown.

* * * * *

Rolling average means the weighted average of all data, meeting QA/QC requirements or otherwise normalized, collected during the applicable averaging period. The period of a rolling average stipulates the frequency of data averaging and reporting. To demonstrate compliance with an operating parameter a 30-day rolling average period requires calculation of a new average value each operating day and shall include the average of all the hourly averages of the specific operating parameter. For demonstration of compliance with an emissions limit based on pollutant concentration a 30-day rolling average is comprised of the average of all the hourly average concentrations over the previous 30 operating days. For demonstration of compliance with an emissions limit based on lbs-pollutant per production unit the 30-day rolling average is calculated by summing the hourly mass emissions over the previous 30 operating days, then dividing that sum by the total production during the same period.

Run average means the average of the recorded parameter values for a run.

* * * * *

■ 8. Section 63.1343 is amended by revising paragraphs (a), (b)(1) and (2), and (d) to read as follows:

§ 63.1343 What standards apply to my kilns, clinker coolers, raw material dryers, and open clinker storage piles?

(a) *General.* The provisions in this section apply to each kiln and any alkali bypass associated with that kiln, clinker cooler, raw material dryer, and open clinker storage pile. All D/F, HCl, and total hydrocarbon (THC) emissions limit are on a dry basis. The D/F, HCl, and THC limits for kilns are corrected to 7 percent oxygen. All THC emissions limits are measured as propane. Standards for mercury and THC are based on a rolling 30-day average. If using a CEMS to determine compliance with the HCl standard, this standard is based on a rolling 30-day average. You must ensure appropriate corrections for moisture are made when measuring flow rates used to calculate mercury emissions. The 30-day period means all operating hours within 30 consecutive kiln operating days excluding periods of startup and shutdown. All emissions limits for kilns, clinker coolers, and raw material dryers currently in effect that are superseded by the limits below continue to apply until the compliance date of the limits below, or until the source certifies compliance with the limits below, whichever is earlier.

(b) *Kilns, clinker coolers, raw material dryers, raw mills, and finish mills.* (1) The emissions limits for these sources are shown in Table 1.

TABLE 1—EMISSIONS LIMITS FOR KILNS, CLINKER COOLERS, RAW MATERIAL DRYERS, RAW AND FINISH MILLS

If your source is a (an):	And the operating mode is:	And if is located at a:	Your emissions limits are:	And the units of the emissions limit are:	The oxygen correction factor is:
1. Existing kiln	Normal operation	Major or area source	PM[1] 0.07 D/F[2] 0.2 Mercury 55 THC[3][4] 24	lb/ton clinker ng/dscm (TEQ) lb/MM tons clinker ppmvd	NA. 7 percent. NA. 7 percent.
2. Existing kiln	Normal operation	Major source	HCl 3	ppmvd	7 percent.
3. Existing kiln	Startup and shutdown	Major or area source	Work practices (63.1346(g)).	NA	NA.
4. New kiln	Normal operation	Major or area source	PM[1] 0.02 D/F[2] 0.2 Mercury 21 THC[3][4] 24	lb/ton clinker ng/dscm (TEQ) lb/MM tons clinker ppmvd	NA. 7 percent. NA. 7 percent.
5. New kiln	Normal operation	Major source	HCl 3	ppmvd	7 percent.
6. New kiln	Startup and shutdown	Major or area source	Work practices (63.1346(g)).	NA	NA.
7. Existing clinker cooler.	Normal operation	Major or area source	PM 0.07	lb/ton clinker	NA.
8. Existing clinker cooler.	Startup and shutdown	Major or area source	Work practices (63.1348(b)(9)).	NA	NA.
9. New clinker cooler	Normal operation	Major or area source	PM 0.02	lb/ton clinker	NA.
10. New clinker cooler	Startup and shutdown	Major or area source	Work practices (63.1348(b)(9)).	NA	NA.
11. Existing or new raw material dryer.	Normal operation	Major or area source	THC[3][4] 24	ppmvd	NA.
12. Existing or new raw material dryer.	Startup and shutdown	Major or area source	Work practices (63.1348(b)(9)).	NA	NA.
13. Existing or new raw or finish mill.	All operating modes	Major source	Opacity 10	percent	NA.

[1] The initial and subsequent PM performance tests are performed using Method 5 or 5I and consist of three test runs.

[2] If the average temperature at the inlet to the first PM control device (fabric filter or electrostatic precipitator) during the D/F performance test is 400 °F or less, this limit is changed to 0.40 ng/dscm (TEQ).

[3] Measured as propane.

[4] Any source subject to the 24 ppmvd THC limit may elect to meet an alternative limit of 12 ppmvd for total organic HAP.

(2) When there is an alkali bypass and/or an inline coal mill with a separate stack associated with a kiln, the combined PM emissions from the kiln and the alkali bypass stack and/or the inline coal mill stack are subject to the PM emissions limit. Existing kilns that combine the clinker cooler exhaust and/or alkali bypass and/or coal mill exhaust with the kiln exhaust and send the combined exhaust to the PM control device as a single stream may meet an alternative PM emissions limit. This limit is calculated using Equation 1 of this section:

$$PM_{alt} = (0.0060 \times 1.65)(Q_k + Q_c + Q_{ab} + Q_{cm})/(7000) \quad \text{(Eq. 1)}$$

Where:

PM_{alt} = Alternative PM emission limit for commingled sources.

0.006 = The PM exhaust concentration (gr/dscf) equivalent to 0.070 lb per ton clinker where clinker cooler and kiln exhaust gas are not combined.

1.65 = The conversion factor of ton feed per ton clinker.

Q_k = The exhaust flow of the kiln (dscf/ton feed).

Q_c = The exhaust flow of the clinker cooler (dscf/ton feed).

Q_{ab} = The exhaust flow of the alkali bypass (dscf/ton feed).

Q_{cm} = The exhaust flow of the coal mill (dscf/ton feed).

7000 = The conversion factor for grains (gr) per lb.

For new kilns that combine kiln exhaust, clinker cooler gas and/or coal mill and alkali bypass exhaust, the limit is calculated using Equation 2 of this section:

$$PM_{alt} = (0.0020 \times 1.65)(Q_k + Q_c + Q_{ab} + Q_{cm})/(7000) \quad \text{(Eq. 2)}$$

Where:

PM_{alt} = Alternative PM emission limit for commingled sources.

0.002 = The PM exhaust concentration (gr/dscf) equivalent to 0.020 lb per ton clinker where clinker cooler and kiln exhaust gas are not combined.

1.65 = The conversion factor of ton feed per ton clinker.

Q_k = The exhaust flow of the kiln (dscf/ton feed).

Q_c = The exhaust flow of the clinker cooler (dscf/ton feed).

Q_{ab} = The exhaust flow of the alkali bypass (dscf/ton feed).

Q_{cm} = The exhaust flow of the coal mill (dscf/ton feed).

7000 = The conversion factor for gr per lb.

* * * * *

(d) Emission limits in effect prior to September 9, 2010. Any source defined as an existing source in § 63.1351, and that was subject to a PM, mercury, THC, D/F, or opacity emissions limit prior to September 9, 2010, must continue to meet the limits as shown in Table 2 until September 9, 2015.

TABLE 2—EMISSIONS LIMITS IN EFFECT PRIOR TO SEPTEMBER 9, 2010, FOR KILNS (ROWS 1–4), CLINKER COOLERS (ROW 5), AND RAW MATERIAL DRYERS (ROWS 6–9)

If your source is	and	And if it is located at	Your emissions limits are: [1]	And the units of the emissions limit are:
1. An existing kiln	it commenced construction or reconstruction on or prior to December 2, 2005.	A major source	PM–0.3 Opacity–20 D/F–0.2 [2] THC–50 [3,4]	lb/ton feed percent ng/dscm (TEQ) ppmvd.
2. An existing kiln	it commenced construction or reconstruction after December 2, 2005.	A major source	PM–0.3 Opacity–20 D/F–0.2 [2] THC–20 [3,5] Mercury–41 [6]	lb/ton feed percent ng/dscm (TEQ) ppmvd ug/dscm.
3. An existing kiln	it commenced construction or reconstruction on or prior to December 2, 2005.	An area source	D/F–0.2 [2] THC–50 [3,4]	ng/dscm (TEQ) ppmvd.
4. An existing kiln	it commenced construction or reconstruction after December 2, 2005.	An area source	D/F–0.2 [2] THC–20 [3,5] Mercury–41 [6]	ng/dscm (TEQ) ppmvd ug/dscm.
5. An existing clinker cooler.	NA	A major source	PM–0.1 Opacity–10	lb/ton feed percent.
6. An Existing raw material dryer.	it commenced construction or reconstruction on or prior to December 2, 2005.	A major source	THC–50 [3,4] Opacity–10	ppmvd Percent.
7. An Existing raw material dryer.	it commenced construction or reconstruction after December 2, 2005.	A major source	THC–20 [3,5] Opacity–10	ppmvd percent.
8. An Existing raw material dryer.	it commenced construction or reconstruction on or prior to December 2, 2005.	An area source	THC–50 [3,4]	ppmvd.
9. An Existing raw material dryer.	it commenced construction or reconstruction after December 2, 2005.	An area source	THC–20 [3,5]	ppmvd.

[1] All emission limits expressed as a concentration basis (ppmvd, ng/dscm) are corrected to seven percent oxygen.

[2] If the average temperature at the inlet to the first particulate matter control device (fabric filter or electrostatic precipitator) during the D/F performance test is 400 °F or less, this limit is changed to 0.4 ng/dscm (TEQ).

[3] Measured as propane.

[4] Only applies to Greenfield kilns or raw material dryers.

[5] As an alternative, a source may demonstrate a 98 percent reduction in THC emissions from the exit of the kiln or raw material dryer to discharge to the atmosphere. Inline raw mills are considered to be an integral part of the kiln.

[6] As an alternative, a source may route the emissions through a packed bed or spray tower wet scrubber with a liquid-to-gas ratio of 30 gallons per 1000 actual cubic feet per minute or more and meet a site-specific emission limit based on the measured performance of the wet scrubber.

§ 63.1344 [Removed and Reserved]

■ 9. Section 63.1344 is removed and reserved.

■ 10. Section 63.1346 is amended by revising paragraph (g)(3)to read as follows:

§ 63.1346 Operating limits for kilns.

* * * * *

(g) * * *

(3) All dry sorbent and activated carbon systems that control hazardous air pollutants must be turned on and operating at the time the gas stream at the inlet to the baghouse or ESP reaches 300 degrees Fahrenheit (five minute average) during startup. Temperature of the gas stream is to be measured at the inlet of the baghouse or ESP every minute. Such injection systems can be turned off during shutdown. Particulate control and all remaining devices that control hazardous air pollutants should be operational during startup and shutdown.

* * * * *

■ 11. Section 63.1347 is amended by revising paragraph (a)(1) to read as follows:

§ 63.1347 Operation and maintenance plan requirements.

(a) * * *

(1) Procedures for proper operation and maintenance of the affected source and air pollution control devices in order to meet the emissions limits and operating limits, including fugitive dust control measures for open clinker piles of §§ 63.1343, 63.1345, and 63.1346. Your operations and maintenance plan must address periods of startup and shutdown.

* * * * *

■ 12. Section 63.1348 is amended by revising paragraphs (a)(4)(iv) and (v), (b)(1)(iii), and (b)(9) to read as follows:

§ 63.1348 Compliance requirements.

(a) * * *

(4) * * *

(iv) The time weighted average total organic HAP concentration measured during the separate initial performance test specified by § 63.1349(b)(7) must be used to determine initial compliance.

(v) The time weighted average THC concentration measured during the initial performance test specified by § 63.1349(b)(4) must be used to determine the site-specific THC limit. Using the fraction of time the inline kiln/raw mill is on and the fraction of time that the inline kiln/raw mill is off, calculate this limit as a time weighted average of the THC levels measured during raw mill on and raw mill off testing using one of the two approaches in § 63.1349(b)(7)(vii) or (viii) depending on the level of organic HAP measured during the compliance test.

* * * * *

(b) * * *

(1) * * *

(iii) You may not use data recorded during monitoring system startup, shutdown or malfunctions or repairs associated with monitoring system malfunctions in calculations used to report emissions or operating levels. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

* * * * *

(9) *Startup and Shutdown Compliance.* All dry sorbent and activated carbon systems that control hazardous air pollutants must be turned on and operating at the time the gas stream at the inlet to the baghouse or ESP reaches 300 degrees Fahrenheit (five minute average) during startup. Temperature of the gas stream is to be measured at the inlet of the baghouse or ESP every minute. Such injection systems can be turned off during shutdown. Particulate control and all remaining devices that control hazardous air pollutants should be operational during startup and shutdown.

* * * * *

■ 13. Section 63.1349 is amended by revising paragraphs (b), (c), and (d)(1)(ii) to read as follows:

§ 63.1349 Performance testing requirements.

* * * * *

(b)(1) *PM emissions tests.* The owner or operator of a kiln and clinker cooler subject to limitations on PM emissions shall demonstrate initial compliance by conducting a performance test using Method 5 or Method 5I at appendix A–3 to part 60 of this chapter. You must also monitor continuous performance through use of a PM continuous parametric monitoring system (PM CPMS).

(i) For your PM CPMS, you will establish a site-specific operating limit. If your PM performance test demonstrates your PM emission levels to be below 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test, the milliamp or digital equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. If your PM compliance test demonstrates your PM emission levels to be at or above 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test to establish your operating limit. You will use the PM CPMS to demonstrate continuous compliance with your operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(A) Your PM CPMS must provide a 4–20 milliamp or digital signal output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps or the monitors digital equivalent.

(B) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to three times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to three times your allowable emission limit.

(C) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp or digital output values from the PM CPMS for the periods corresponding to the compliance test runs (*e.g.,* average all your PM CPMS output values for three corresponding Method 5I test runs).

(ii) Determine your operating limit as specified in paragraphs (b)(1)(iii) through (iv) of this section. If your PM performance test demonstrates your PM emission levels to be below 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test, the milliamp or digital equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. If your PM compliance test demonstrates your PM emission levels to be at or above 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test to establish your operating limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test at least annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(iii) If the average of your three Method 5 or 5I compliance test runs is below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or 5I compliance test with the procedures in (b)(1)(iii)(A) through (D) of this section.

(A) Determine your PM CPMS instrument zero output with one of the following procedures:

(*1*) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*2*) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*3*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (*e.g.,* when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*4*) If none of the steps in paragraphs (b)(1)(iii)(A)(*1*) through (*3*) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your PM CPMS instrument average in milliamps or digital equivalent, and the average of your corresponding three PM compliance test runs, using equation 3.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 3)}$$

Where:

X_1 = The PM CPMS data points for the three runs constituting the performance test.

Y_1 = The PM concentration value for the three runs constituting the performance test.

n = The number of data points.

(C) With your instrument zero expressed in milliamps or a digital value, your three run average PM CPMS milliamp or digital signal value, and your three run PM compliance test average, determine a relationship of lb/ton-clinker per milliamp or digital signal value with Equation 4.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 4)}$$

Where:

R = The relative lb/ton-clinker per milliamp or digital equivalent for your PM CPMS.

Y_1 = The three run average lb/ton-clinker PM concentration.

X_1 = The three run average milliamp or digital equivalent output from your PM CPMS.

z = The milliamp or digital equivalent of your instrument zero determined from (b)(1)(iii)(A).

* * * * *

(D) Determine your source specific 30-day rolling average operating limit using the lb/ton-clinker per milliamp or digital signal value from Equation 4 in Equation 5, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_1 = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 5)}$$

Where:

* * * * *

O_1 = The operating limit for your PM CPMS on a 30-day rolling average, in milliamps or the digital equivalent.

L = Your source emission limit expressed in lb/ton clinker.

z = Your instrument zero in milliamps, or digital equivalent, determined from (b)(1)(iii)(A).

R = The relative lb/ton-clinker per milliamp, or digital equivalent, for your PM CPMS, from Equation 4.

* * * * *

(iv) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your operating limit by averaging the PM CPMS milliamp or digital equivalent output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using Equation 6.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 6)}$$

Where:

* * * * *

X_1 = The PM CPMS data points for all runs i.

n = The number of data points.

O_h = Your site specific operating limit, in milliamps or the digital equivalent.

* * * * *

(v) To determine continuous operating compliance, you must record the PM CPMS output data for all periods when the process is operating, and use all the PM CPMS data for calculations when the source is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps or the digital equivalent) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 7 to determine the 30 kiln operating day average.

$$30\text{kiln operating day} = \frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 7)}$$

Where:

Hpvi = The hourly parameter value for hour i.

n = The number of valid hourly parameter values collected over 30 kiln operating days.

* * * * *

(vi) For each performance test, conduct at least three separate test runs each while the mill is on and the mill is off, under the conditions that exist when the affected source is operating at the level reasonably expected to occur. Conduct each test run to collect a minimum sample volume of 2 dscm for determining compliance with a new source limit and 1 dscm for determining compliance with an existing source limit. Calculate the time weighted average of the results from three consecutive runs, including applicable sources as required by (b)(1)(viii), to determine compliance. You need not determine the particulate matter collected in the impingers (''back half'') of the Method 5 or Method 5I particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the ''back half'' for other purposes.

(vii) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (*e.g.* beta attenuation), span of the instruments primary analytical range, milliamp value or digital equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp or digital equivalent signals corresponding to each PM compliance test run.

(viii) When there is an alkali bypass and/or an inline coal mill with a separate stack associated with a kiln, the main exhaust and alkali bypass and/or inline coal mill must be tested simultaneously and the combined emission rate of PM from the kiln and alkali bypass and/or inline coal mill must be computed for each run using Equation 8 of this section.

$$E_{Cm} = \frac{E_K + E_B + E_C}{P} \qquad \text{(Eq. 8)}$$

Where:

E_{Cm} = Combined hourly emission rate of PM from the kiln and bypass stack and/or inline coal mill, lb/ton of kiln clinker production.

E_K = Hourly emissions of PM emissions from the kiln, lb.

E_B = Hourly PM emissions from the alkali bypass stack, lb.

E_C = Hourly PM emissions from the inline coal mill stack, lb.

P = Hourly clinker production, tons.

(ix) The owner or operator of a kiln with an in-line raw mill and subject to limitations on PM emissions shall demonstrate initial compliance by conducting separate performance tests while the raw mill is under normal operating conditions and while the raw mill is not operating, and calculate the time weighted average emissions. The operating limit will then be determined using 63.1349(b)(1)(i) of this section.

(2) *Opacity tests.* If you are subject to limitations on opacity under this subpart, you must conduct opacity tests in accordance with Method 9 of appendix A–4 to part 60 of this chapter. The duration of the Method 9 performance test must be 3 hours (30 6-minute averages), except that the duration of the Method 9 performance test may be reduced to 1 hour if the conditions of paragraphs (b)(2)(i) and (ii) of this section apply. For batch processes that are not run for 3-hour periods or longer, compile observations totaling 3 hours when the unit is operating.

(i) There are no individual readings greater than 10 percent opacity;

(ii) There are no more than three readings of 10 percent for the first 1-hour period.

(3) *D/F Emissions Tests.* If you are subject to limitations on D/F emissions under this subpart, you must conduct a performance test using Method 23 of appendix A–7 to part 60 of this chapter. If your kiln or in-line kiln/raw mill is equipped with an alkali bypass, you must conduct simultaneous performance tests of the kiln or in-line kiln/raw mill exhaust and the alkali bypass. You may conduct a performance test of the alkali bypass exhaust when the raw mill of the in-line kiln/raw mill is operating or not operating.

(i) Each performance test must consist of three separate runs conducted under representative conditions. The duration of each run must be at least 3 hours, and the sample volume for each run must be at least 2.5 dscm (90 dscf).

(ii) The temperature at the inlet to the kiln or in-line kiln/raw mill PMCD, and, where applicable, the temperature at the inlet to the alkali bypass PMCD must be continuously recorded during the period of the Method 23 test, and the continuous temperature record(s) must be included in the performance test report.

(iii) Average temperatures must be calculated for each run of the performance test.

(iv) The run average temperature must be calculated for each run, and the average of the run average temperatures must be determined and included in the performance test report and will determine the applicable temperature limit in accordance with § 63.1346(b), footnote 2.

(v)(A) If sorbent injection is used for D/F control, you must record the rate of sorbent injection to the kiln exhaust, and where applicable, the rate of sorbent injection to the alkali bypass exhaust, continuously during the period of the Method 23 test in accordance with the conditions in § 63.1350(m)(9), and include the continuous injection rate record(s) in the performance test report. Determine the sorbent injection rate parameters in accordance with paragraph (b)(3)(vi) of this section.

(B) Include the brand and type of sorbent used during the performance test in the performance test report.

(C) Maintain a continuous record of either the carrier gas flow rate or the carrier gas pressure drop for the duration of the performance test. If the carrier gas flow rate is used, determine, record, and maintain a record of the accuracy of the carrier gas flow rate monitoring system according to the procedures in appendix A to part 75 of this chapter. If the carrier gas pressure drop is used, determine, record, and maintain a record of the accuracy of the carrier gas pressure drop monitoring system according to the procedures in § 63.1350(m)(6).

(vi) Calculate the run average sorbent injection rate for each run and determine and include the average of the run average injection rates in the performance test report and determine the applicable injection rate limit in accordance with § 63.1346(c)(1).

(4) *THC emissions test.* (i) If you are subject to limitations on THC emissions, you must operate a CEMS in accordance with the requirements in § 63.1350(i). For the purposes of conducting the accuracy and quality assurance evaluations for CEMS, the THC span value (as propane) is 50 ppmvd and the reference method (RM) is Method 25A of appendix A to part 60 of this chapter.

(ii) Use the THC CEMS to conduct the initial compliance test for the first 30 kiln operating days of kiln operation after the compliance date of the rule. See § 63.1348(a).

(iii) If kiln gases are diverted through an alkali bypass or to a coal mill and exhausted through a separate stack, you must calculate a kiln-specific THC limit using Equation 9:

$$Cks = \frac{(MACT\ Limit\ x\ (Qab+Qcm+Qks))-(Qab\ x\ Cab)-(Qcm\ x\ Ccm)}{Qks} \quad \text{(Eq. 9)}$$

Where:

Cks = Kiln stack concentration (ppmvd).
Qab = Alkali bypass flow rate (volume/hr).
Cab = Alkali bypass concentration (ppmvd).
Qcm = Coal mill flow rate (volume/hr).
Ccm = Coal mill concentration (ppmvd).
Qks = Kiln stack flow rate (volume/hr).

(iv) THC must be measured either upstream of the coal mill or the coal mill stack.

(v) Instead of conducting the performance test specified in paragraph (b)(4)of this section, you may conduct a performance test to determine emissions of total organic HAP by following the procedures in paragraph (b)(7) of this section.

(5) *Mercury Emissions Tests.* If you are subject to limitations on mercury emissions, you must operate a mercury CEMS or a sorbent trap monitoring system in accordance with the requirements of § 63.1350(k). The initial compliance test must be based on the first 30 kiln operating days in which the affected source operates using a mercury CEMS or a sorbent trap monitoring system after the compliance date of the rule. See § 63.1348(a).

(i) If you are using a mercury CEMS or a sorbent trap monitoring system, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the exhaust gas flow rate to the atmosphere according to the requirements in § 63.1350(k)(5).

(ii) Calculate the emission rate using Equation 10 of this section:

$$E_{30D} = k\,\frac{\sum_{i=1}^{n} C_i Q_i}{P} \quad \text{(Eq. 10)}$$

Where:

E_{30D} = 30-day rolling emission rate of mercury, lb/MM tons clinker.
C_i = Concentration of mercury for operating hour i, µg/scm.
Q_i = Volumetric flow rate of effluent gas for operating hour i, where C_i and Q_i are on the same basis (either wet or dry), scm/hr.
k = Conversion factor, 1 lb/454,000,000 µg.
n = Number of kiln operating hours in the previous 30 kiln operating day period where both C and Qi qualified data are available.
P = Total runs from the previous 30 days of clinker production during the same time period as the mercury emissions measured, million tons.

(6) *HCl emissions tests.* For a source subject to limitations on HCl emissions you must conduct performance testing by one of the following methods:

(i)(A) If the source is equipped with a wet scrubber, tray tower or dry scrubber, you must conduct performance testing using Method 321 of appendix A to this part unless you have installed a CEMS that meets the requirements § 63.1350(l)(1). For kilns with inline raw mills, testing should be conducted for the raw mill on and raw mill off conditions.

(B) You must establish site specific parameter limits by using the CPMS required in § 63.1350(l)(1). For a wet scrubber or tray tower, measure and record the pressure drop across the scrubber and/or liquid flow rate and pH in intervals of no more than 15 minutes during the HCl test. Compute and record the 24-hour average pressure drop, pH, and average scrubber water flow rate for each sampling run in which the applicable emissions limit is met. For a dry scrubber, measure and record the sorbent injection rate in intervals of no more than 15 minutes during the HCl test. Compute and record the 24-hour average sorbent injection rate and average sorbent injection rate for each sampling run in which the applicable emissions limit is met.

(ii)(A) If the source is not controlled by a wet scrubber, tray tower or dry sorbent injection system, you must operate a CEMS in accordance with the requirements of § 63.1350(l)(1). See § 63.1348(a).

(B) The initial compliance test must be based on the 30 kiln operating days that occur after the compliance date of this rule in which the affected source operates using an HCl CEMS. Hourly HCl concentration data must be obtained according to § 63.1350(l).

(iii) As an alternative to paragraph (b)(6)(i)(B) of this section, you may choose to monitor SO_2 emissions using a CEMS in accordance with the requirements of § 63.1350(l)(3). You must establish an SO_2 operating limit equal to the average recorded during the HCl stack test where the HCl stack test run result demonstrates compliance with the emission limit. This operating limit will apply only for demonstrating HCl compliance.

(iv) If kiln gases are diverted through an alkali bypass or to a coal mill and exhausted through a separate stack, you must calculate a kiln-specific HCl limit using Equation 11:

$$Cks = \frac{(MACT\ Limit\ x\ (Qab+Qcm+Qks))-(Qab\ x\ Cab)-(Qcm\ x\ Ccm)}{Qks} \quad \text{(Eq. 11)}$$

Where:

Cks = Kiln stack concentration (ppmvd).
Qab = Alkali bypass flow rate (volume/hr).

Cab = Alkali bypass concentration (ppmvd).
Qcm = Coal mill flow rate (volume/hr).
Ccm = Coal mill concentration (ppmvd).
Qks = Kiln stack flow rate (volume/hr).

(7) *Total Organic HAP Emissions Tests.* Instead of conducting the performance test specified in paragraph (b)(4) of this section, you may conduct a performance test to determine emissions of total organic HAP by following the procedures in paragraphs (b)(7)(i) through (v) of this section.

(i) Use Method 320 of appendix A to this part, Method 18 of Appendix A of part 60, ASTM D6348–03 or a combination to determine emissions of total organic HAP. Each performance test must consist of three separate runs under the conditions that exist when the affected source is operating at the representative performance conditions in accordance with § 63.7(e). Each run must be conducted for at least 1 hour.

(ii) At the same time that you are conducting the performance test for total organic HAP, you must also determine a site-specific THC emissions limit by operating a THC CEMS in accordance with the requirements of § 63.1350(j). The duration of the performance test must be at least 3 hours and the average THC concentration (as calculated from the recorded output) during the 3-hour test must be calculated. You must establish your THC operating limit and determine compliance with it according to paragraphs (b)(7)(vii) and (viii) of this section. It is permissible to extend the testing time of the organic HAP performance test if you believe extended testing is required to adequately capture organic HAP and/or THC variability over time.

(iii) If your source has an in-line kiln/raw mill you must use the fraction of time the raw mill is on and the fraction of time that the raw mill is off and calculate this limit as a weighted average of the THC levels measured during three raw mill on and three raw mill off tests.

(iv) If your organic HAP emissions are below 75 percent of the organic HAP standard and you determine your operating limit with paragraph (b)(7)(vii) of this section your THC CEMS must be calibrated and operated on a measurement scale no greater than 180 ppmvw, as carbon, or 60 ppmvw as propane.

(v) If your kiln has an inline coal mill and/or an alkali bypass with separate stacks, you are required to measure and account for oHAP emissions from their separate stacks. You are required to measure oHAP at the coal mill inlet, and you must also measure oHAP at the alkali bypass outlet. You must then calculate a flow weighted average oHAP concentration for all emission sources including the inline coal mill and the alkali bypass.

(vi) Your THC CEMS measurement scale must be capable of reading THC concentrations from zero to a level equivalent to two times your highest THC emissions average determined during your performance test, including mill on or mill off operation. **NOTE:** This may require the use of a dual range instrument to meet this requirement and paragraph (b)(7)(iv) of this section.

(vii) Determine your operating limit as specified in paragraphs (b)(7)(viii) and (ix) of this section. If your organic HAP performance test demonstrates your average organic HAP emission levels are below 75 percent of your emission limit (9 ppmv) you will use the average THC value recorded during the organic HAP performance test, and the average total organic HAP result of your performance test to establish your operating limit. If your organic HAP compliance test results demonstrate that your average organic HAP emission levels are at or above 75 percent of your emission limit, your operating limit is established as the average THC value recorded during the organic HAP performance test. You must establish a new operating limit after each performance test. You must repeat the performance test no later than 30 months following your last performance test and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(viii) If the average organic HAP results for your three Method 18 and/or Method 320 performance test runs are below 75 percent of your organic HAP emission limit, you must calculate an operating limit by establishing a relationship of THC CEMS signal to the organic HAP concentration using the average THC CEMS value corresponding to the three organic HAP compliance test runs and the average organic HAP total concentration from the Method 18 and/or Method 320 performance test runs with the procedures in (b)(7)(viii)(A) and (B) of this section.

(A) Determine the THC CEMS average values in ppmvw, and the average of your corresponding three total organic HAP compliance test runs, using Equation 12.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1 ,\bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 12)}$$

Where:
$\bar{x}$ = The THC CEMS average values in ppmvw.
X_i = The THC CEMS data points for all three runs i.
Y_i = The sum of organic HAP concentrations for test runs i. and
n = The number of data points.

(B) You must use your three run average THC CEMS value and your three run average organic HAP concentration from your three Method 18 and/or Method 320 compliance tests to determine the operating limit. Use equation 13 to determine your operating limit in units of ppmvw THC, as propane.

$$T_1 = \left(\frac{9}{Y_1}\right) * X_1 \qquad \text{(Eq. 13)}$$

Where:
T_l = The 30-day operating limit for your THC CEMS, ppmvw.
Y_1 = The average organic HAP concentration from Eq. 12, ppmvd.
X_1 = The average THC CEMS concentration from Eq. 12, ppmvw.

(ix) If the average of your three organic HAP performance test runs is at or above 75 percent of your organic HAP emission limit, you must determine your operating limit using Equation 14 by averaging the THC CEMS output values corresponding to your three organic HAP performance test runs that demonstrate compliance with the emission limit. If your new THC CEMS value is below your current operating limit, you may opt to retain your current operating limit, but you must still submit all performance test and THC CEMS data according to the reporting requirements in paragraph (d)(1) of this section.

$$T_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 14)}$$

Where:

X_1 = The THC CEMS data points for all runs i.

n = The number of data points.

T_h = Your site specific operating limit, in ppmvw THC.

(x) If your kiln has an inline kiln/raw mill, you must conduct separate performance tests while the raw mill is operating (''mill on'') and while the raw mill is not operating (''mill off''). Using the fraction of time the raw mill is on and the fraction of time that the raw mill is off, calculate this limit as a weighted average of the THC levels measured during raw mill on and raw mill off compliance testing with Equation 15.

$$R=(y*t)+(x*(1-t)) \qquad \text{(Eq.15)}$$

Where:

R = Operating limit as THC, ppmvw.

y = Average THC CEMS value during mill on operations, ppmvw.

t = Percentage of operating time with mill on.

x = Average THC CEMS value during mill off operations, ppmvw.

(1-t) = Percentage of operating time with mill off.

(xi) To determine continuous compliance with the THC operating limit, you must record the THC CEMS output data for all periods when the process is operating and the THC CEMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the THC CEMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (ppmvw) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 16 to determine the 30 kiln operating day average.

$$\text{30kiln operating day} = \frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 16)}$$

Where:

Hpvi = The hourly parameter value for hour i, ppmvw.

n = The number of valid hourly parameter values collected over 30 kiln operating days.

(xii) Use EPA Method 18 or Method 320 of appendix A to part 60 of this chapter to determine organic HAP emissions. For each performance test, conduct at least three separate runs under the conditions that exist when the affected source is operating at the level reasonably expected to occur. If your source has an in-line kiln/raw mill you must conduct three separate test runs with the raw mill on, and three separate runs under the conditions that exist when the affected source is operating at the level reasonably expected to occur with the mill off. Conduct each Method 18 test run to collect a minimum target sample equivalent to three times the method detection limit. Calculate the average of the results from three runs to determine compliance.

(xiii) If the THC level exceeds by 10 percent or more your site-specific THC emissions limit, you must

(A) As soon as possible but no later than 30 days after the exceedance, conduct an inspection and take corrective action to return the THC CEMS measurements to within the established value; and

(B) Within 90 days of the exceedance or at the time of the 30 month compliance test, whichever comes first, conduct another performance test to determine compliance with the organic HAP limit and to verify or re-establish your site-specific THC emissions limit.

(8) HCl Emissions Tests with SO_2 Monitoring. If you choose to monitor SO_2 emissions using a CEMS to demonstrate HCl compliance, follow the procedures in (b)(8)(i) through (ix) of this section and in accordance with the requirements of § 63.1350(l)(3). You must establish an SO_2 operating limit equal to the average recorded during the HCl stack test. This operating limit will apply only for demonstrating HCl compliance.

(i) Use Method 321 of appendix A to this part to determine emissions of HCl. Each performance test must consist of three separate runs under the conditions that exist when the affected source is operating at the representative performance conditions in accordance with § 63.7(e). Each run must be conducted for at least one hour.

(ii) At the same time that you are conducting the performance test for HCl, you must also determine a site-specific SO_2 emissions limit by operating an SO_2 CEMS in accordance with the requirements of § 63.1350(l). The duration of the performance test must be three hours and the average SO_2 concentration (as calculated from the average output) during the 3-hour test must be calculated. You must establish your SO_2 operating limit and determine compliance with it according to paragraphs (b)(8)(vii) and (viii) of this section.

(iii) If your source has an in-line kiln/raw mill you must use the fraction of time the raw mill is on and the fraction of time that the raw mill is off and calculate this limit as a weighted average of the SO_2 levels measured during raw mill on and raw mill off testing.

(iv) Your SO_2 CEMS must be calibrated and operated according to the requirements of § 60.63(f).

(v) Your SO_2 CEMS measurement scale must be capable of reading SO_2 concentrations consistent with the requirements of § 60.63(f), including mill on or mill off operation.

(vi) If your kiln has an inline kiln/raw mill, you must conduct separate performance tests while the raw mill is operating (''mill on'') and while the raw mill is not operating (''mill off''). Using the fraction of time the raw mill is on and the fraction of time that the raw mill is off, calculate this limit as a weighted average of the HCl levels measured during raw mill on and raw mill off compliance testing with Equation 17.

$$R=(y*t)+x*(L-1) \qquad \text{(Eq. 17)}$$

Where:

R = Operating limit as SO_2, ppmvw.
y = Average SO_2 CEMS value during mill on operations, ppmvw.
t = Percentage of operating time with mill on, expressed as a decimal.
x = Average SO_2 CEMS value during mill off operations, ppmvw.
$t-1$ = Percentage of operating time with mill off, expressed as a decimal.

(vii) If the average of your three HCl compliance test runs is below 75 percent of your HCl emission limit, you may as a compliance alternative, calculate an operating limit by establishing a relationship of SO_2 CEMS signal to your HCl concentration corrected to 7 percent O_2 by using the SO_2 CEMS instrument zero, the average SO_2 CEMS values corresponding to the three compliance test runs, and the average HCl concentration from the HCl compliance test with the procedures in (b)(8)(vii)(A) through (D) of this section.

(A) Determine your SO_2 CEMS instrument zero output with one of the following procedures:

(*1*) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*2*) Zero point data for extractive instruments may be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*3*) The zero point may also be established by performing probe-flood introduction of high purity nitrogen or certified zero air free of SO_2.

(*4*) If none of the steps in paragraphs (b)(8)(vii)(A)(*1*) through (*3*) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your SO_2 CEMS instrument average ppm, and the average of your corresponding three HCl compliance test runs, using equation 18.

$$\bar{x}=\frac{1}{n}\sum_{i=1}^{n}X_1,\ \bar{y}=\frac{1}{n}\sum_{i=1}^{n}Y_1 \qquad \text{(Eq. 18)}$$

Where:

X_1 = The SO_2 CEMS data points for the three runs constituting the performance test.
Y_1 = The HCl emission concentration expressed as ppmv corrected to 7 percent O_2 for the three runs constituting the performance test.
n = The number of data points.

(C) With your instrument zero expressed in ppmv, your three run average SO_2 CEMS expressed in ppmv, and your three run HCl compliance test average in ppm corrected to 7 percent O_2, determine a relationship of ppm HCl corrected to 7 percent O_2 per ppm SO_2 with Equation 19.

$$R=\frac{Y_1}{(X_1-z)} \qquad \text{(Eq. 19)}$$

Where:

R = The relative HCl ppmv corrected to 7 percent O_2 per ppm SO_2 for your SO_2 CEMS.
Y_1 = The three run average HCl concentration corrected to 7 percent O_2.
X_1 = The three run average ppm recorded by your SO_2 CEMS.
z = The instrument zero output ppm value.

(D) Determine your source specific 30-day rolling average operating limit using ppm HCl corrected to 7 percent O_2 per ppm SO_2 value from Equation 19 in Equation 20, below. This sets your operating limit at the SO_2 CEMS ppm value corresponding to 75 percent of your emission limit.

$$O_1=z+\frac{0.75(L)}{R} \qquad \text{(Eq. 20)}$$

Where:

O_l = The operating limit for your SO_2 CEMS on a 30-day rolling average, in ppmv.
L = Your source HCl emission limit expressed in ppmv corrected to 7 percent O_2.
z = Your instrument zero in ppmv, determined from (1)(i).
R = The relative oxygen corrected ppmv HCl per ppmv SO_2, for your SO_2 CEMS, from Equation 19.

(viii) To determine continuous compliance with the SO_2 operating limit, you must record the SO_2 CEMS output data for all periods when the process is operating and the SO_2 CEMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the SO_2 CEMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (ppmvw) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 21 to determine the 30 kiln operating day average.

$$30kiln\ operating\ day=\frac{\sum_{i=1}^{n}Hpvi}{n} \qquad \text{(Eq. 21)}$$

Where:

Hpvi = The hourly parameter value for hour i, ppmvw.

n = The number of valid hourly parameter values collected over 30 kiln operating days.

(ix) Use EPA Method 321 of appendix A to part 60 of this chapter to determine HCl emissions. For each performance test, conduct at least three separate runs under the conditions that exist when the affected source is operating at the level reasonably expected to occur. If your source has an in-line kiln/raw mill you must conduct three separate test runs with the raw mill on, and three separate runs under the conditions that exist when the affected source is operating at the level reasonably expected to occur with the mill off.

(x) If the SO_2 level exceeds by 10 percent or more your site-specific SO_2 emissions limit, you must:

(A) As soon as possible but no later than 30 days after the exceedance, conduct an inspection and take corrective action to return the SO_2 CEMS measurements to within the established value;

(B) Within 90 days of the exceedance or at the time of the periodic compliance test, whichever comes first, conduct another performance test to determine compliance with the HCl limit and to verify or re-establish your site-specific SO_2 emissions limit.

(c) *Performance test frequency.* Except as provided in § 63.1348(b), performance tests are required at regular intervals for affected sources that are subject to a dioxin, organic HAP or HCl emissions limit. Performance tests required every 30 months must be completed between 29 and 31 calendar months after the previous performance test except where that specific pollutant is monitored using CEMS; performance tests required every 12 months must be completed within 11 to 13 calendar months after the previous performance test.

* * * * *

(d) * * *

(1) * * *

(ii) The values for the site-specific operating limits or parameters established pursuant to paragraphs (b)(1), (3), (6), (7), and (8) of this section, as applicable, and a description, including sample calculations, of how the operating parameters were established during the initial performance test.

* * * * *

■ 14. Section 63.1350 is amended by:

■ a. Removing and reserving paragraph (a)(2).

■ b. Revising paragraphs (i)(1) and (2), (j), (k)(2) introductory text, and (k)(2)(ii).

■ c. Adding paragraph (k)(2)(iii).

■ d. Revising paragraphs (k)(5)(i) and (iv), (l), (n) introductory text, (n)(1) and (4), (o) introductory text, and (o)(3) introductory text.

The revisions and additions read as follows:

§ 63.1350 Monitoring requirements.

* * * * *

(i) * * *

(1) You must install, operate, and maintain a THC continuous emission monitoring system in accordance with Performance Specification 8 or Performance Specification 8A of appendix B to part 60 of this chapter and comply with all of the requirements for continuous monitoring systems found in the general provisions, subpart A of this part. The owner or operator must operate and maintain each CEMS according to the quality assurance requirements in Procedure 1 of appendix F in part 60 of this chapter. For THC continuous emission monitoring systems certified under Performance Specification 8A, conduct the relative accuracy test audits required under Procedure 1 in accordance with Performance Specification 8, Sections 8 and 11 using Method 25A in appendix A to 40 CFR part 60 as the reference method; the relative accuracy must meet the criteria of Performance Specification 8, Section 13.2.

(2) Performance tests on alkali bypass and coal mill stacks must be conducted using Method 25A in appendix A to 40 CFR part 60 and repeated every 30 months.

(j) *Total organic HAP monitoring requirements.* If you are complying with the total organic HAP emissions limits, you must continuously monitor THC according to paragraph (i)(1) and (2) of this section or in accordance with Performance Specification 8 or Performance Specification 8A of appendix B to part 60 of this chapter and comply with all of the requirements for continuous monitoring systems found in the general provisions, subpart A of this part. You must operate and maintain each CEMS according to the quality assurance requirements in Procedure 1 of appendix F in part 60 of this chapter. In addition, your must follow the monitoring requirements in paragraphs (m)(1) through (4) of this section. You must also develop an emissions monitoring plan in accordance with paragraphs (p)(1) through (4) of this section.

(k) * * *

(2) In order to quality assure data measured above the span value, you must use one of the three options in paragraphs (k)(2)(i) through (iii) of this section. Where the options in paragraphs (k)(2)(i) through (iii) are employed while the kiln is operating in a mill-off mode, the ''above span'' described in paragraph (k)(2)(iii) may substitute for the daily upscale calibration provided the data normalization process in paragraph (k)(2)(iii) are not required. If data normalization is required, the normal daily upscale calibration check must be performed to quality assure the operation of the CEMS for that day. In this particular case, adjustments to CEMS normally required by Procedure 5 when a daily upscale does not meet the 5 percent criterion are not required, unless paragraph (k)(2)(iii) of this section data normalization is necessary and a subsequent normal daily calibration check demonstrates the need for such adjustment.

* * * * *

(ii) Quality assure any data above the span value by proving instrument linearity beyond the span value established in paragraph (k)(1) of this section using the following procedure. Conduct a weekly ''above span linearity'' calibration challenge of the monitoring system using a reference gas with a certified value greater than your highest expected hourly concentration or greater than 75 percent of the highest measured hourly concentration. The ''above span'' reference gas must meet the requirements of PS 12A, Section 7.1 and must be introduced to the measurement system at the probe. Record and report the results of this procedure as you would for a daily calibration. The ''above span linearity'' challenge is successful if the value measured by the Hg CEMS falls within 10 percent of the certified value of the reference gas. If the value measured by the Hg CEMS during the above span linearity challenge exceeds +/−10 percent of the certified value of the reference gas, the monitoring system must be evaluated and repaired and a new ''above span linearity'' challenge met before returning the Hg CEMS to service, or data above span from the Hg CEMS must be subject to the quality assurance procedures established in paragraph (k)(2)(iii) of this section. In this manner values measured by the Hg CEMS during the above span linearity challenge exceeding +/−20 percent of the certified value of the reference gas must be normalized using Equation 22.

(iii) Quality assure any data above the span value established in paragraph (k)(1) of this section using the following procedure. Any time two consecutive one-hour average measured concentrations of Hg exceeds the span value you must, within 24 hours before or after, introduce a higher, ''above span'' Hg reference gas standard to the Hg CEMS. The ''above span'' reference gas must meet the requirements of PS 12A, Section 7.1, must target a concentration level between 50 and 150 percent of the highest expected hourly concentration measured during the period of measurements above span, and must be introduced at the probe. While this target represents a desired concentration range that is not always achievable in practice, it is expected that the intent to meet this range is demonstrated by the value of the reference gas. Expected values may include ''above span'' calibrations done before or after the above span measurement period. Record and report the results of this procedure as you would for a daily calibration. The ''above span'' calibration is successful if the value measured by the Hg CEMS is within 20 percent of the certified value of the reference gas. If the value measured by the Hg CEMS exceeds 20 percent of the certified value of the reference gas, then you must normalize the one-hour average stack gas values measured above the span during the 24-hour period preceding or following the ''above span'' calibration for reporting based on the Hg CEMS response to the reference gas as shown in equation 22:

$$\frac{\textit{Certified reference gas value}}{\textit{Measured value of reference gas}} \; x \; \textit{Measured stack gas result} = \textit{Normalized stack gas result} \qquad (Eq. 22)$$

Only one ''above span'' calibration is needed per 24 hour period. If the ''above span'' calibration is conducted during the period when measured emissions are above span and there is a failure to collect at least one valid data point in an hour due to the calibration duration, then you must determine the emissions average for that missed hour as the average of hourly averages for the hour preceding the missed hour and the hour following the missed hour. In an hour where an ''above span'' calibration is being conducted and one or more data points are collected, the emissions average is represented by the average of all valid data points collected in that hour.

* * * * *

(5) * * *

(i) Develop a mercury hourly mass emissions rate by conducting performance tests annually, within 11 to 13 calendar months after the previous performance test, using Method 29, or Method 30B, to measure the concentration of mercury in the gases exhausted from the alkali bypass and coal mill.

* * * * *

(iv) If mercury emissions from the coal mill and alkali bypass are below the method detection limit for two consecutive annual performance tests, you may reduce the frequency of the performance tests of coal mills and alkali bypasses to once every 30 months. If the measured mercury concentration exceeds the method detection limit, you must revert to testing annually until two consecutive annual tests are below the method detection limit.

* * * * *

(l) *HCl Monitoring Requirements.* If you are subject to an emissions limitation on HCl emissions in § 63.1343, you must monitor HCl emissions continuously according to paragraph (l)(1) or (2) and paragraphs (m)(1) through (4) of this section or, if your kiln is controlled using a wet or dry scrubber or tray tower, you alternatively may parametrically monitor SO_2 emissions continuously according to paragraph (l)(3) of this section. You must also develop an emissions monitoring plan in accordance with paragraphs (p)(1) through (4) of this section.

(1) If you monitor compliance with the HCl emissions limit by operating an HCl CEMS, you must do so in accordance with Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, or, upon promulgation, in accordance with any other performance specification for HCl CEMS in appendix B to part 60 of this chapter. You must operate, maintain, and quality assure a HCl CEMS installed and certified under PS 15 according to the quality assurance requirements in Procedure 1 of appendix F to part 60 of this chapter except that the Relative Accuracy Test Audit requirements of Procedure 1 must be replaced with the validation requirements and criteria of sections 11.1.1 and 12.0 of PS 15. When promulgated, if you choose to install and operate an HCl CEMS in accordance with PS 18 of appendix B to part 60 of this chapter, you must operate, maintain and quality assure the HCl CEMS using the associated Procedure 6 of appendix F to part 60 of this chapter. For any performance specification that you use, you must use Method 321 of appendix A to part 63 of this chapter as the reference test method for conducting relative accuracy testing. The span value and calibration requirements in paragraphs (l)(1)(i) and (ii) of this section apply to all HCl CEMS used under this subpart.

(i) You must use a measurement span value for any HCl CEMS of 0–10 ppmvw unless the monitor is installed on a kiln without an inline raw mill. Kilns without an inline raw mill may use a higher span value sufficient to quantify all expected emissions concentrations. The HCl CEMS data recorder output range must include the full range of expected HCl concentration values which would include those expected during ''mill off'' conditions. The corresponding data recorder range shall be documented in the site-specific monitoring plan and associated records.

(ii) In order to quality assure data measured above the span value, you must use one of the three options in paragraphs (l)(1)(ii)(A) through (C) of this section.

(A) Include a second span that encompasses the HCl emission concentrations expected to be encountered during ''mill off'' conditions. This second span may be rounded to a multiple of 5 ppm of total HCl. The requirements of the appropriate HCl monitor performance specification shall be followed for this second span with the exception that a RATA with the mill off is not required.

(B) Quality assure any data above the span value by proving instrument linearity beyond the span value established in paragraph (l)(1)(i) of this section using the following procedure. Conduct a weekly ''above span linearity'' calibration challenge of the monitoring system using a reference gas with a certified value greater than your highest expected hourly concentration or greater than 75 percent of the highest measured hourly concentration. The ''above span'' reference gas must meet the requirements of the applicable performance specification and must be introduced to the measurement system at the probe. Record and report the results of this procedure as you would for a daily calibration. The ''above span linearity’’ challenge is successful if the value measured by the HCl CEMS falls within 10 percent of the certified value of the reference gas. If the value measured by the HCl CEMS during the above span linearity challenge exceeds 10 percent of the certified value of the reference gas, the monitoring system must be evaluated and repaired and a new ‘‘above span linearity’’ challenge met before returning the HCl CEMS to service, or data above span from the HCl CEMS must be subject to the quality assurance procedures established in paragraph (l)(1)(ii)(D) of this section. Any HCl CEMS above span linearity challenge exceeding +/-20 percent of the certified value of the reference gas requires that all above span data must be normalized using Equation 23.

(C) Quality assure any data above the span value established in paragraph (l)(1)(i) of this section using the following procedure. Any time two consecutive one-hour average measured concentration of HCl exceeds the span value you must, within 24 hours before or after, introduce a higher, ‘‘above span’’ HCl reference gas standard to the HCl CEMS. The ‘‘above span’’ reference gas must meet the requirements of the applicable performance specification and target a concentration level between 50 and 150 percent of the highest expected hourly concentration measured during the period of measurements above span, and must be introduced at the probe. While this target represents a desired concentration range that is not always achievable in practice, it is expected that the intent to meet this range is demonstrated by the value of the reference gas. Expected values may include above span calibrations done before or after the above-span measurement period. Record and report the results of this procedure as you would for a daily calibration. The ‘‘above span’’ calibration is successful if the value measured by the HCl CEMS is within 20 percent of the certified value of the reference gas. If the value measured by the HCl CEMS is not within 20 percent of the certified value of the reference gas, then you must normalize the stack gas values measured above span as described in paragraph (l)(1)(ii)(D) of this section. If the ‘‘above span’’ calibration is conducted during the period when measured emissions are above span and there is a failure to collect at least one valid data point in an hour due to the calibration duration, then you must determine the emissions average for that missed hour as the average of hourly averages for the hour preceding the missed hour and the hour following the missed hour. In an hour where an ‘‘above span’’ calibration is being conducted and one or more data points are collected, the emissions average is represented by the average of all valid data points collected in that hour.

(D) In the event that the ‘‘above span’’ calibration is not successful (*i.e.,* the HCl CEMS measured value is not within 20 percent of the certified value of the reference gas), then you must normalize the one-hour average stack gas values measured above the span during the 24-hour period preceding or following the ‘above span’ calibration for reporting based on the HCl CEMS response to the reference gas as shown in Equation 23:

$$\frac{\text{Certified reference gas value}}{\text{Measured value of reference gas}}\ x\ \text{Measured stack gas result} = \text{Normalized stack gas result} \qquad (Eq. 23)$$

Only one ‘‘above span’’ calibration is needed per 24-hour period.

(2) Install, operate, and maintain a CMS to monitor wet scrubber or tray tower parameters, as specified in paragraphs (m)(5) and (7) of this section, and dry scrubber, as specified in paragraph (m)(9) of this section.

(3) If the source is equipped with a wet or dry scrubber or tray tower, and you choose to monitor SO_2 emissions, monitor SO_2 emissions continuously according to the requirements of § 60.63(e) and (f) of part 60 subpart F of this chapter. If SO_2 levels increase above the 30-day rolling average SO_2 operating limit established during your performance test, you must:

(i) As soon as possible but no later than 48 hours after you exceed the established SO_2 value conduct an inspection and take corrective action to return the SO_2 emissions to within the operating limit; and

(ii) Within 60 days of the exceedance or at the time of the next compliance test, whichever comes first, conduct an HCl emissions compliance test to determine compliance with the HCl emissions limit and to verify or re-establish the SO_2 CEMS operating limit.

* * * * *

(n) *Continuous Flow Rate Monitoring System.* You must install, operate, calibrate, and maintain instruments, according to the requirements in paragraphs (n)(1) through (10) of this section, for continuously measuring and recording the stack gas flow rate to allow determination of the pollutant mass emissions rate to the atmosphere from sources subject to an emissions limitation that has a pounds per ton of clinker unit and that is required to be monitored by a CEMS.

(1) You must install each sensor of the flow rate monitoring system in a location that provides representative measurement of the exhaust gas flow rate at the sampling location of the mercury CEMS, taking into account the manufacturer’s recommendations. The flow rate sensor is that portion of the system that senses the volumetric flow rate and generates an output proportional to that flow rate.

* * * * *

(4) The flow rate monitoring system must be equipped with a data acquisition and recording system that is capable of recording values over the entire range specified in paragraph (n)(2) of this section.

* * * * *

(o) *Alternate monitoring requirements approval.* You may submit an application to the Administrator for approval of alternate monitoring requirements to demonstrate compliance with the emission standards of this subpart subject to the provisions of paragraphs (o)(1) through (6) of this section.

* * * * *

(3) You must submit the application for approval of alternate monitoring requirements no later than the notification of performance test. The application must contain the information specified in paragraphs (o)(3)(i) through (iii) of this section:

* * * * *

■ 15. 63.1354 is amended by revising paragraphs (b)(9) introductory text through (b)(9)(vi) and adding paragraphs (b)(9)(viii) through (x) to read as follows:

§ 63.1354 Reporting requirements.

* * * * *

(b) * * *

(9) The owner or operator shall submit a summary report semiannually to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*).) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report the Administrator at the appropriate address listed in § 63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. The reports must be submitted by the deadline specified in this subpart, regardless of the method in which the reports are submitted. The report must contain the information specified in § 63.10(e)(3)(vi). In addition, the summary report shall include:

(i) All exceedances of maximum control device inlet gas temperature limits specified in § 63.1346(a) and (b);

(ii) Notification of any failure to calibrate thermocouples and other temperature sensors as required under § 63.1350(g)(1)(iii) of this subpart; and

(iii) Notification of any failure to maintain the activated carbon injection rate, and the activated carbon injection carrier gas flow rate or pressure drop, as applicable, as required under § 63.1346(c)(2).

(iv) Notification of failure to conduct any combustion system component inspections conducted within the reporting period as required under § 63.1347(a)(3).

(v) Any and all failures to comply with any provision of the operation and maintenance plan developed in accordance with § 63.1347(a).

(vi) For each PM CPMS, HCl, Hg, and THC CEMS, D/F temperature monitoring system, or Hg sorbent trap monitoring system, within 60 days after the reporting periods, you must report all of the calculated 30-operating day rolling average values derived from the CPMS, CEMS, CMS, or Hg sorbent trap monitoring systems.

* * * * *

(viii) Within 60 days after the date of completing each CEMS performance evaluation test as defined in § 63.2, you must submit relative accuracy test audit (RATA) data to the EPA's CDX by using CEDRI in accordance with paragraph (b)(9) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in § 63.13.

(ix) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (*e.g.* beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(x) All reports required by this subpart not subject to the requirements in paragraphs (b)(9) introductory text and (b)(9)(viii) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.,* by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (b)(9) introductory text and (b)(9)(viii) of this section in paper format.

* * * * *

§ 63.1355 [Amended]

■ 16. Amend § 63.1355 by removing and reserving paragraph (d).

■ 17. Revise § 63.1356 to read as follows:

§ 63.1356 Sources with multiple emissions limit or monitoring requirements.

If you have an affected source subject to this subpart with a different emissions limit or requirement for the same pollutant under another regulation in title 40 of this chapter, once you are in compliance with the most stringent emissions limit or requirement, you are not subject to the less stringent requirement. Until you are in compliance with the more stringent limit, the less stringent limit continues to apply.

§ 63.1357 [Removed and Reserved]

■ 18. Remove and reserve § 63.1357.

■ 19. Revise Table 1 to Subpart LLL of Part 63 to read as follows:

TABLE 1 TO SUBPART LLL OF PART 63—APPLICABILITY OF GENERAL PROVISIONS

Citation	Requirement	Applies to subpart LLL	Explanation
63.1(a)(1)–(4)	Applicability	Yes.	
63.1(a)(5)		No	[Reserved].
63.1(a)(6)–(8)	Applicability	Yes.	
63.1(a)(9)		No	[Reserved].
63.1(a)(10)–(14)	Applicability	Yes.	
63.1(b)(1)	Initial Applicability Determination	No	§ 63.1340 specifies applicability.
63.1(b)(2)–(3)	Initial Applicability Determination	Yes.	
63.1(c)(1)	Applicability After Standard Established	Yes.	
63.1(c)(2)	Permit Requirements	Yes	Area sources must obtain Title V permits.
63.1(c)(3)		No	[Reserved].
63.1(c)(4)–(5)	Extensions, Notifications	Yes.	
63.1(d)		No	[Reserved].
63.1(e)	Applicability of Permit Program	Yes.	
63.2	Definitions	Yes	Additional definitions in § 63.1341.
63.3(a)–(c)	Units and Abbreviations	Yes.	
63.4(a)(1)–(3)	Prohibited Activities	Yes.	
63.4(a)(4)		No	[Reserved].
63.4(a)(5)	Compliance date	Yes.	

Table 1 to Subpart LLL of Part 63—Applicability of General Provisions—Continued

Citation	Requirement	Applies to subpart LLL	Explanation
63.4(b)–(c)	Circumvention, Severability	Yes.	
63.5(a)(1)–(2)	Construction/Reconstruction	Yes.	
63.5(b)(1)	Compliance Dates	Yes.	
63.5(b)(2)		No	[Reserved].
63.5(b)(3)–(6)	Construction Approval, Applicability	Yes.	
63.5(c)		No	[Reserved].
63.5(d)(1)–(4)	Approval of Construction/Reconstruction	Yes.	
63.5(e)	Approval of Construction/Reconstruction	Yes.	
63.5(f)(1)–(2)	Approval of Construction/Reconstruction	Yes.	
63.6(a)	Compliance for Standards and Maintenance.	Yes.	
63.6(b)(1)–(5)	Compliance Dates	Yes.	
63.6(b)(6)		No	[Reserved].
63.6(b)(7)	Compliance Dates	Yes.	
63.6(c)(1)–(2)	Compliance Dates	Yes.	
63.6(c)(3)–(4)		No	[Reserved].
63.6(c)(5)	Compliance Dates	Yes.	
63.6(d)		No	[Reserved].
63.6(e)(1)–(2)	Operation & Maintenance	No	See § 63.1348(d) for general duty requirement. Any reference to § 63.6(e)(1)(i) in other General Provisions or in this subpart is to be treated as a cross-reference to § 63.1348(d).
63.6(e)(3)	Startup, Shutdown Malfunction Plan	No	Your operations and maintenance plan must address periods of startup and shutdown. See § 63.1347(a)(1).
63.6(f)(1)	Compliance with Emission Standards	No	Compliance obligations specified in subpart LLL.
63.6(f)(2)–(3)	Compliance with Emission Standards	Yes.	
63.6(g)(1)–(3)	Alternative Standard	Yes.	
63.6(h)(1)	Opacity/VE Standards	No	Compliance obligations specified in subpart LLL.
63.6(h)(2)	Opacity/VE Standards	Yes.	
63.6(h)(3)		No	[Reserved].
63.6(h)(4)–(h)(5)(i)	Opacity/VE Standards	Yes.	
63.6(h)(5)(ii)–(iv)	Opacity/VE Standards	No	Test duration specified in subpart LLL.
63.6(h)(6)	Opacity/VE Standards	Yes.	
63.6(h)(7)	Opacity/VE Standards	Yes.	
63.6(i)(1)–(14)	Extension of Compliance	Yes.	
63.6(i)(15)		No	[Reserved].
63.6(i)(16)	Extension of Compliance	Yes.	
63.6(j)	Exemption from Compliance	Yes.	
63.7(a)(1)–(3)	Performance Testing Requirements	Yes	§ 63.1349 has specific requirements.
63.7(b)	Notification period	Yes	Except for repeat performance test caused by an exceedance. See § 63.1353(b)(6).
63.7(c)	Quality Assurance/Test Plan	Yes.	
63.7(d)	Testing Facilities	Yes.	
63.7(e)(1)	Conduct of Tests	No	See § 63.1349(e). Any reference to 63.7(e)(1) in other General Provisions or in this subpart is to be treated as a cross-reference to § 63.1349(e).
63.7(e)(2)–(4)	Conduct of tests	Yes.	
63.7(f)	Alternative Test Method	Yes.	
63.7(g)	Data Analysis	Yes.	
63.7(h)	Waiver of Tests	Yes.	
63.8(a)(1)	Monitoring Requirements	Yes.	
63.8(a)(2)	Monitoring	No	§ 63.1350 includes CEMS requirements.
63.8(a)(3)		No	[Reserved].
63.8(a)(4)	Monitoring	No	Flares not applicable.
63.8(b)(1)–(3)	Conduct of Monitoring	Yes.	
63.8(c)(1)–(8)	CMS Operation/Maintenance	Yes	Temperature and activated carbon injection monitoring data reduction requirements given in subpart LLL.
63.8(d)	Quality Control	Yes, except for the reference to the SSM Plan in the last sentence.	
63.8(e)	Performance Evaluation for CMS	Yes.	
63.8(f)(1)–(5)	Alternative Monitoring Method	Yes	Additional requirements in § 63.1350(l).
63.8(f)(6)	Alternative to RATA Test	Yes.	
63.8(g)	Data Reduction	Yes.	

TABLE 1 TO SUBPART LLL OF PART 63—APPLICABILITY OF GENERAL PROVISIONS—Continued

Citation	Requirement	Applies to subpart LLL	Explanation
63.9(a)	Notification Requirements	Yes.	
63.9(b)(1)–(5)	Initial Notifications	Yes.	
63.9(c)	Request for Compliance Extension	Yes.	
63.9(d)	New Source Notification for Special Compliance Requirements.	Yes.	
63.9(e)	Notification of performance test	Yes	Except for repeat performance test caused by an exceedance. See § 63.1353(b)(6).
63.9(f)	Notification of VE/Opacity Test	Yes	Notification not required for VE/opacity test under § 63.1350(e) and (j).
63.9(g)	Additional CMS Notifications	Yes.	
63.9(h)(1)–(3)	Notification of Compliance Status	Yes.	
63.9(h)(4)		No	[Reserved].
63.9(h)(5)–(6)	Notification of Compliance Status	Yes.	
63.9(i)	Adjustment of Deadlines	Yes.	
63.9(j)	Change in Previous Information	Yes.	
63.10(a)	Recordkeeping/Reporting	Yes.	
63.10(b)(1)	General Recordkeeping Requirements	Yes.	
63.10(b)(2)(i)–(ii)	General Recordkeeping Requirements	No	See § 63.1355(g) and (h).
63.10(b)(2)(iii)	General Recordkeeping Requirements	Yes.	
63.10(b)(2)(iv)–(v)	General Recordkeeping Requirements	No.	
63.10(b)(2)(vi)–(ix)	General Recordkeeping Requirements	Yes.	
63.10(c)(1)	Additional CMS Recordkeeping	Yes	PS–8A supersedes requirements for THC CEMS.
63.10(c)(1)	Additional CMS Recordkeeping	Yes	PS–8A supersedes requirements for THC CEMS.
63.10(c)(2)–(4)		No	[Reserved].
63.10(c)(5)–(8)	Additional CMS Recordkeeping	Yes	PS–8A supersedes requirements for THC CEMS.
63.10(c)(9)		No	[Reserved].
63.10(c)(10)–(15)	Additional CMS Recordkeeping	Yes	PS–8A supersedes requirements for THC CEMS.
63.10(d)(1)	General Reporting Requirements	Yes.	
63.10(d)(2)	Performance Test Results	Yes.	
63.10(d)(3)	Opacity or VE Observations	Yes.	
63.10(d)(4)	Progress Reports	Yes.	
63.10(d)(5)	Startup, Shutdown, Malfunction Reports	No	See § 63.1354(c) for reporting requirements. Any reference to § 63.10(d)(5) in other General Provisions or in this subpart is to be treated as a cross-reference to § 63.1354(c).
63.10(e)(1)–(2)	Additional CMS Reports	Yes.	
63.10(e)(3)	Excess Emissions and CMS Performance Reports.	Yes	Exceedances are defined in subpart LLL.
63.10(e)(3)(vii) and (viii)	Excess Emissions and CMS Performance Reports.	No	Superseded by 63.1354(b)(10).
63.10(f)	Waiver for Recordkeeping/Reporting	Yes.	
63.11(a)–(b)	Control Device Requirements	No	Flares not applicable.
63.12(a)–(c)	State Authority and Delegations	Yes.	
63.13(a)–(c)	State/Regional Addresses	Yes.	
63.14(a)–(b)	Incorporation by Reference	Yes.	
63.15(a)–(b)	Availability of Information	Yes.	

[FR Doc. 2015–16811 Filed 7–24–15; 8:45 am]

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the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by October 13, 2015. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. *See* section 307(b)(2).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Ozone, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: July 30, 2015.

Heather McTeer Toney,

Regional Administrator, Region 4.

40 CFR part 52 is amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

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

Subpart K—Florida

■ 2. Section 52.520(c) is amended under Chapter 62–252 by:

■ a. Removing the entries for ''62–252–.100,'' ''62–252–.200,'' ''62–252–.400,'' ''62–252–.500,'' ''62–252–.800'', and ''62–252–.900'' and

■ b. Revising the entry for ''62–252–.300.''

The revision reads as follows:

§ 52.520 Identification of plan.

* * * * *

(c) * * *

EPA-APPROVED FLORIDA REGULATIONS

State citation (Section)	Title/subject	State effective date	EPA approval date	Explanation
*	*	*	*	*
62–252.300	Gasoline Dispensing Facilities Stage I Vapor Recovery.	5/1/2015	8/12/2015 [Insert citation of publication].	
*	*	*	*	*

* * * * *

[FR Doc. 2015–19721 Filed 8–11–15; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505; FRL–9931–76–OAR]

RIN 2060–AS49

Oil and Natural Gas Sector: Definitions of Low Pressure Gas Well and Storage Vessel

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes amendments to new source performance standards (NSPS) for the Oil and Natural Gas Sector. On March 23, 2015, the Environmental Protection Agency (EPA) re-proposed its definition of ''low pressure gas well'' for notice and comment to correct a procedural defect with its prior rulemaking that included this definition. The EPA also proposed to amend the NSPS to remove provisions concerning storage vessels connected or installed in parallel and to revise the definition of ''storage vessel.'' This action finalizes the definition of ''low pressure gas well'' and the amendments to the storage vessel provisions.

DATES: The final rule is effective on August 12, 2015.

ADDRESSES: The EPA has established a docket for this rulemaking under Docket ID Number EPA–HQ–OAR–2010–0505. All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information 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. Publicly available docket materials are available either electronically in regulations.gov or in hard copy at the EPA Docket Center, EPA WJC West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For further information on this action, contact Mr. Matthew Witosky, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–2865; facsimile number: (919) 541–3470; email address: *witosky.matthew@epa.gov.* For further information on the EPA's Oil and Natural Gas Sector regulatory program for air, contact Mr. Bruce Moore, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 541–3470; email address: *moore.bruce@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this reconsideration action apply to me?

Categories and entities potentially affected by this action include:

Category	NAICS code[1]	Examples of regulated entities
Industry	211111	Crude Petroleum and Natural Gas Extraction.
	211112	Natural Gas Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 (General Provisions).

B. How do I obtain 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 World Wide Web (WWW). Following signature by the EPA Administrator, a copy of this proposed action will be posted at the following address: *http://www.epa.gov/airquality/oilandgas/actions.html.*

C. Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of this final rule is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by October 13, 2015. Under section 307(d)(7)(B) of the CAA, only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established in this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements. Section 307(d)(7)(B) of the CAA 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 us 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 (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 EPA, Room 3000, EPA WJC West 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. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Background

A. Low Pressure Gas Wells

On August 23, 2011 (76 FR 52758), the EPA proposed the Oil and Natural Gas Sector NSPS (40 CFR part 60, subpart OOOO). Among the elements of the proposed rule were provisions for reduced emission completion (REC), also known as ''green completion'' of hydraulically fractured gas wells. In the proposal, the EPA solicited comment on situations where conducting a REC would be infeasible. Several commenters highlighted technical issues that prevent the implementation of a REC on what they referred to as ''low pressure'' gas wells because of the lack of the necessary reservoir pressure to flow at rates appropriate for the transportation of solids and liquids from a hydraulically fractured gas well completion against additional backpressure which would be caused by the REC equipment. Based on our analysis of the public comments received, we determined that there are certain wells where a REC is technically infeasible because of the characteristics of the reservoir and the well depth that will not allow the flowback to overcome the gathering system pressure due to the additional backpressure imposed by the REC surface equipment.

On August 16, 2012, the EPA published the final NSPS (77 FR 49490). Under the 2012 NSPS, a REC is not required for well completions of low pressure gas wells. Rather, the 2012 final NSPS requires at 40 CFR 60.5375(f) that well completions of low pressure gas wells using hydraulic fracturing meet the requirements for combustion of flowback emissions and to the general duty to safely maximize resource recovery and minimize releases to the atmosphere required under 40 CFR 60.5375(a)(4).

The 2012 NSPS includes a definition of ''low pressure gas well'' that is based on a mathematical formula that takes into account a well's depth, reservoir pressure, and flow line pressure. Section 60.5430 defines low pressure gas well as ''a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.''

Following publication of the 2012 NSPS, a group of petitioners, led by the Independent Petroleum Association of America (IPAA), representing independent oil and natural gas owners and operators, submitted a joint petition for administrative reconsideration of the rule. The petitioners questioned the technical merits of the low pressure well definition and asserted that the public had not had an opportunity to comment on the definition because it was added in the final rule.[1]

On March 24, 2014, the petitioners submitted to the EPA a suggested alternative definition[2] for consideration. The petitioners' definition is based on the fresh water hydrostatic gradient of 0.433 pounds per square inch per foot (psi/ft). The petitioners assert that this approach is straightforward and has been recognized for many years in the oil and natural gas industry and by governmental agencies and professional organizations. As expressed in the paper submitted by the

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[1] Letter from James D. Elliott, Spilman, Thomas & Battle PLLC, to Lisa P. Jackson, EPA Administrator, October 15, 2012; Petition for Administrative Reconsideration of Final Rule ''Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews,'' 77 FR 49490 (August 16, 2012).

[2] Email from James D. Elliott, Spilman, Thomas & Battle PLLC, to Bruce Moore, EPA, March 24, 2014.

petitioners, the alternative definition for consideration by the EPA, as stated by the petitioners, would be ''a well where the field pressure is less than 0.433 times the vertical depth of the deepest target reservoir and the flow-back period will be less than three days in duration.''

On July 17, 2014, the EPA proposed clarifying amendments to the gas well completion provisions of the NSPS. In the July proposal, we re-proposed the definition of ''low pressure gas well'' for notice and comment. We also discussed the alternative definition provided by the IPAA. Specifically, we expressed concern that the IPAA alternative definition is too simplistic and may not adequately account for the parameters that must be considered when determining whether a REC would be feasible for a given hydraulically fractured gas well. We expressed disagreement with the petitioners' assertion that the EPA definition is too complicated and that it would pose difficulty or hardship for smaller operators. However, we agreed with the petitioners that the public should have been provided an opportunity to comment on the 2012 definition of ''low pressure gas well,'' and we, therefore, re-proposed the 2012 definition for notice and comment. In addition, we solicited comment on the alternative definition suggested by the petitioners.

On August 18, 2014, prior to the close of the public comment period for the July 17, 2014, proposal, the IPAA, on behalf of the independent oil and natural gas owner and operator petitioners, submitted a comment to the EPA via the email address to the Air and Radiation Docket provided in the proposed rule.

The EPA published final amendments in the **Federal Register** at 79 FR 79018 on December 31, 2014, which finalized the definition of ''low pressure gas well'' unchanged from the 2012 definition. Subsequent to the December 31, 2014, publication of the final amendments, the EPA became aware that the comment submitted by the IPAA was not made part of the record in the docket and, thus, was not available to be considered by the EPA in its decision-making process prior to finalizing the amendments. On March 23, 2015 (80 FR 15180), the EPA re-proposed the definition of ''low pressure gas well'', and took comment on IPAA's alternative definition to correct the procedural defect.

B. Storage Vessels Connected in Parallel

In the December 31, 2014, final rule, the EPA finalized amendments to the NSPS to address, among other issues, the affected facility status of storage vessel affected facilities. The final action included amendments related to storage vessels ''connected in parallel'' or ''installed in parallel.'' As we explained in the final rule preamble (79 FR 79027), ''Although we believe it is an unlikely occurrence, we note that, when two or more storage vessels receive liquids in parallel, the total throughput is shared between or among the parallel vessels and, in turn, this causes the PTE of each vessel to be a fraction of the total PTE.'' To address such isolated occurrences where storage vessels are installed or connected to reduce the potential to emit (PTE) and, therefore, avoid being subject to 40 CFR part 60, subpart OOOO, we amended the NSPS to address situations in which two or more storage vessels could be installed or connected in parallel which could, in some cases, lower the PTE of the individual storage vessels to levels below the 6 tons per year (tpy) applicability threshold provided in 40 CFR 60.5365(e). Specifically, we amended 40 CFR 60.5365(e)(4) to provide that a storage vessel that is being placed into service, and is connected in parallel with a storage vessel affected facility, is immediately subject to the same requirements as the affected facility with which it is being connected in parallel. We also amended the definitions for ''returned to service'' and ''storage vessel'' in 40 CFR 60.5430 to provide that two or more storage vessels connected in parallel are considered equivalent to a single storage vessel with throughput equal to the total throughput of the storage vessels connected in parallel.

Following publication of the December 2014 final rule, we became aware that the terms ''connected in parallel'' and ''installed in parallel'' inadvertently included storage vessels beyond those we attempted to address as described above. On February 19, 2015, the Gas Processors Association (GPA) submitted a petition for administrative reconsideration of the December 31, 2014, amendments. The GPA asserted that ''it is quite common for multiple storage vessels to be situated next to each other and connected in parallel. Sometimes the storage vessels are operated in parallel, sometimes they are operated in series, and sometimes they are operated one-at-a-time with the connecting valves closed.'' The GPA further asserted that this configuration has existed for decades and that ''this language potentially has large impacts to how our members evaluate affected facility status.'' For the reasons discussed above, we proposed to remove the regulatory provisions relative to storage vessels ''installed in parallel'' or ''connected in parallel.''

III. Summary of Final Amendments

This section presents a summary of the provisions of the final action with brief explanations where appropriate. In some cases, additional detailed discussions are provided in section IV and V of this preamble, as well as the Response to Comment document. The final amendments include revisions to certain reconsidered aspects of the 2012 NSPS as follows: (1) Definition of ''low pressure gas well''; (2) definition of ''returned to service''; (3) definition of ''storage vessel''; (4) revision of 40 CFR 60.5365(e)(4) to remove the phrases ''or is installed in parallel with any storage vessel affected facility,'' and ''or with which it is installed in parallel.''

A. Low Pressure Gas Wells

The EPA is finalizing its definition of ''low pressure gas well.'' For the purposes of 40 CFR part 60, subpart OOOO, our definition of low pressure gas well is for a singular purpose—to identify the wells that cannot implement a REC because of a lack of necessary reservoir pressure to flow gas at rates appropriate for the transportation of solids and liquids from a hydraulically fractured gas well against additional backpressure that would be caused by the REC equipment, thereby making a REC infeasible (80 FR 15182).

In response to comments, we are amending the definition of ''low pressure gas well'' in this final action by changing ''vertical depth'' to ''true vertical depth.'' This change more accurately reflects our intent when formulating the definition of ''low pressure gas well.''

B. Storage Vessels Connected in Parallel

The EPA is revising the definition of ''storage vessel'' to remove references to ''connected in parallel'' and ''installed in parallel'' from the current definition, and making associated changes to 40 CFR 60.5365(e)(4). We are not making any changes to the proposed definition of ''storage vessel.''

IV. Significant Changes Since Proposal

There is only one significant change since proposal, which is to refer to ''true vertical depth'' (instead of ''vertical depth'') in the definition of ''low pressure gas well.'' Several commenters took issue that the proposal definition of ''low pressure gas well'' does not take into account the ''true vertical depth'' of the well, as the ''vertical depth'' of the well can overstate actual vertical depth because well bores may not be absolutely vertical. The commenters concluded that measured vertical depth often exceeds the true vertical depth of a well bore. The commenters believe this is an important distinction, especially for directional or horizontal wells, that should be clarified in the definition.

We agree with the commenters that ''true vertical depth'' is more accurate terminology that better represents our intent. In light of the above considerations, we are amending the definition of ''low pressure gas well'' in this action by changing ''vertical depth'' to ''true vertical depth.''

V. Summary of Significant Comments and Responses

This section summarizes the significant comments on our proposed amendments and our responses.

A. Definition of ''Low Pressure Gas Well''

Comment: One commenter noted that the EPA's defense of the low pressure well definition focuses on the level of burden the definition imposes on the industry. The commenter contended that the EPA is missing the point with this response. The commenter contended that their concern is not the hardship imposed by the calculation required by the definition but rather that the definition does not accurately depict what historically has been considered to be a low pressure gas well. Thus, according to the commenter, the current definition would require RECs to be performed on marginally cost-effective wells.

Response: In the 2012 rulemaking, EPA concluded that the BSER for well completion was a combination of REC and combustion; however, in response to comment that REC is not technically feasible for ''low pressure gas wells'' due to the inability of such wells to attain a gas velocity sufficient to clean up the well when flowing against the backpressure imposed by the surface equipment and the flow line pressure, the EPA exempted ''low pressure gas wells'' from REC in the 2012 NSPS. The EPA subsequently re-proposed its ''low pressure gas well'' definition in response to an administrative petition that notice or an opportunity to comment was not provided for the EPA's 2012 definition of ''low pressure gas well.'' However, rather than commenting on parameters for defining ''technical infeasibility'' to implement REC, the commenter asks the EPA to consider other burdens and hardships in defining ''low pressure wells.'' In the 2015 re-proposal of the ''low pressure gas well'' definition, the EPA did not propose or otherwise contempt exempting well completions from performing REC for reasons beyond technical infeasibility. This request is thus beyond the purpose and scope of this re-proposal, which is to provide a low pressure well definition that would accurately describe wells for which REC is technically infeasible due to low pressure and, therefore, exempt from the REC requirements under 40 CFR part 60, subpart OOOO.

Comment: Several commenters expressed support for the alternative definition of ''low pressure gas well'' provided by IPAA as being more representative of current industry practice of defining these wells.

According to one commenter, the alternative definition is based on the fresh water gradient, is widely used in industry, and appropriately describes the well conditions where installation of REC equipment is impractical. The commenter stated that the fresh water gradient (*i.e.,* 0.433 psi/ft or 8.33 pounds(lbs)/gallon (gal) × 0.052 × True Vertical Depth (TVD)) represents normally pressured wells based on the hydrostatic overhead pressure of fresh water that increases linearly with TVD. If reservoir pressure is less than the hydrostatic pressure of water, the well will not flow on its own because of the overhead pressure of fracture fluids in the wellbore that will be higher than the reservoir pressure which may make REC equipment impractical. The commenter added that whether a well's productive reservoir pressure is above or below the water gradient may be readily confirmed by reading offset reservoir pressure data in the development field or by evaluating certain wireline well logs that may be run after drilling a well before well completion begins.

Another commenter stated that the EPA's current definition does not accurately define what industry has historically defined and recognized as a low pressure well. According to the commenter, because EPA's definition does not accurately delineate low pressure wells, the current definition will subject a subset of wells to RECs where the operation of a separator is not physically possible, thereby making the wells uneconomical as a result of being subject to REC requirements. The commenter included a table showing the values calculated using the EPA's definition for various well depths and flow line pressures. According to the commenter, the alternate definition would classify all of the values in the table as a low pressure well, while the EPA's definition would only consider about a quarter of the wells as low pressure.

The commenter further stated that the permeability of the reservoir and other reservoir characteristics play a critical role in determining when a well is low pressure well or under-pressured. In addition to overcoming the hydrostatic pressure and sale line pressure, the separator necessary for the REC adds to the pressure which must be overcome for gas to flow from the reservoir. The commenter stated that the separator pressure is arguably the controlling parameter on when a REC is feasible versus the sales line pressure. Unlike the sales line pressure, which is easily known, the commenter contended that the separator pressure can vary greatly depending on gas and liquid rates, liquid composition, and equipment limitations. The commenter pointed out that the EPA's definition does not take separator pressure into account, thereby making the definition overly conservative. The commenter admitted that the alternative definition does not contain an adjustment for separator pressure either, but the definition is more accurate and is inclusive of wells recognized by the industry as ''low pressure.''

In addition to the pressure associated with the separator, the commenter stated that in order for a separator to function, there must be a sufficient volume of gas (at appropriate pressure) to lift the associated liquids and overcome the pressure of the separator. The commenter added that if that gas rate is not achieved, the well will load up and a REC will not be possible. According to the commenter, the gas rate necessary for a REC varies based on reservoir pressure and casing/tubing diameter. The commenter provided a graph of Coleman curves to illustrate this point, which illustrates that as the pressure and casing diameter increase, so must the gas rate.

Response: The EPA believes that the alternative definition of ''low pressure gas well,'' based only on fresh water gradient, may not adequately account for the parameters that must be taken into account when determining whether a REC would be feasible for a given hydraulically fractured gas well. We believe that, to determine whether the flowback gas has sufficient pressure to flow into a flow line, it is necessary to account for reservoir pressure, well depth, and flow line pressure. In addition, it is important for any such determination to take into account pressure losses in the surface equipment used to perform the REC. The EPA's definition in the proposed rule was developed to account for these factors.

The EPA agrees that there must be a sufficient volumetric flow of gas (caused by adequate reservoir pressure) to lift the associated liquids and overcome the pressure of the separator, enabling the gas to be collected (*i.e.,* enter the flow line). However, the EPA disagrees that the current definition, which we re-proposed for notice and comment, does not take into account the additional backpressure caused by the REC equipment, including a separator. The model uses an energy balance to determine the pressure drop based on the calculated velocity, and then the model accounts for pressure losses caused by REC equipment, including the separator. The result of the model is a prediction of the pressure of the flowback gas immediately before it enters the flow line. The result can be compared to the actual flow line pressure available to the well. For wells with insufficient pressure to produce into the flow line, as predicted using the EPA equation, combustion must be used to control emissions. For wells with sufficient pressure to produce into the flow line, gas capture in combination with combustion must be used to control emissions.

According to some of the commenters, the EPA's definition of low pressure gas well should be revised because it does not comport with what the industry has historically considered to be a low pressure gas well. We are not making a determination on the similarity of the two definitions because we do not believe that the two must be the same for purposes of the Oil and Gas NSPS. The EPA has provided a definition of ''low pressure gas well'' in the NSPS in order to designate a class of wells where a REC is not technically feasible. Our definition of ''low pressure gas well'' in the NSPS is for a singular purpose—to identify the wells that cannot implement a REC because of a lack of necessary reservoir pressure to flow gas at rates appropriate for the transportation of solids and liquids from a hydraulically fractured gas well during flowback against additional backpressure which would be caused by the REC equipment, thereby making a REC technically infeasible (80 FR 15182). To the extent that the industry definition is different from the EPA definition, the industry likely defines a particular well as being low pressure for a variety of reasons.[3] As such, it is not clear that a REC is not technically infeasible for all of the wells that the industry has historically considered to be ''low pressure wells.''

B. Revisions to the Alternate Definition

Comment: One commenter stated that the alternative definition should also be clarified to state ''where field reservoir pressure is less than 0.433 times the *true* vertical depth of the reservoir.'' According to the commenter, referring to reservoir pressure adds clarity and true vertical depth is a well-known standard term in the industry to differentiate from ''measured depth,'' where measured depth is the length of the well. The commenters stated this is an important distinction, especially for directional or horizontal wells, that should be clarified in the low pressure well definition.

Another commenter similarly suggested that instead of defining the term ''low pressure gas well'' in terms of the ''vertical depth'' of the deepest target reservoir, it should instead by defined in terms of the ''true vertical depth.'' The commenter cited to the Schlumberger online Oil Field Glossary, which defines ''true vertical depth'' as follows:

> The vertical distance from a point in the well (usually the current or final depth) to a point at the surface, usually the elevation of the rotary kelly bushing (RKB). This is one of two primary depth measurements used by the drillers, the other being measured depth. TVD is important in determining bottomhole pressures, which are caused in part by the hydrostatic head of fluid in the wellbore. For this calculation, measured depth is irrelevant and TVD must be used. For most other operations, the driller is interested in the length of the hole or how much pipe will fit into the hole. For those measurements, measured depth, not TVD, is used. While the drilling crew should be careful to designate which measurement they are referring to, if no designation is used, they are usually referring to measured depth. Note that measured depth, due to intentional or unintentional curves in the wellbore, is always longer than true vertical depth.

The commenter stated that it would be better to use ''true vertical depth'' because the measured vertical depth can overstate actual vertical depth because well bores may not be absolutely vertical. Thus, measured vertical depth often exceeds the true vertical depth of a well bore.

One commenter stated that the IPAA's proposed definition for ''low pressure well'' was based on the weight of fresh water (8.33 lbs/gal) which is stacked on top of itself, and is known as hydrostatic pressure. Converting the density of fresh water to a pressure gradient results in 8.33 lb/gal being equal to 0.433 psi/ft. Therefore, the pressure of fresh water in the well bore is 0.433 psi/ft times the vertical well depth.

The commenter added that in reality, the fluid flowing to the surface could be fresh water, re-used hydraulic fracturing water, re-used, produced water, or a mixture. Additionally, in the beginning of the operation, the commenter stated that initial fluids flowing to the surface are essentially the fracturing fluids put down hole. At the end of the operation, the fluids flowing to the surface will mainly consist of reservoir fluids, and the water will be more of a brine water and not fresh water. The commenter added that brine water has a greater density, and more reservoir pressure will be required to lift the fluid to the surface. The commenter contended that the use of a fresh water gradient of 0.433 psi/ft should be used to keep the definition conservative and simple.

As an alternative, or in addition, to a fresh water gradient, the commenter recommended that the density of brine water influenced by sand or proppant should be used to more accurately reflect the pressure of the water column in the well bore. The commenter pointed out that the EPA appears to have utilized a gradient of 0.4645 psi/ft in the ''Lessons Learned from Natural Gas STAR Partners; Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells'' paper developed as a part of the EPA's Natural Gas STAR Program. The commenter stated that this is evidenced by the gradients listed in Exhibit 5 of the paper. Additionally, to perform a REC, the commenter contended that the downhole reservoir pressure must be sufficient enough to lift the hydraulic fracturing fluid to the surface and through the separation equipment and piping, with the resulting gas still having enough backpressure for it to get into the natural gas gathering line. According to the commenter, to combust flowback emissions the downhole reservoir pressure must be sufficient enough to lift the hydraulic fracturing fluid to the surface and through the separation equipment and piping, with the resulting gas still having enough backpressure to flow to a flare or enclosed combustion device.

To reflect these realities, the commenter proposed that no emission

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[3] ''USEPA's proposed low pressure well definition forces controls on a segment of the industry that have no or minimal beneficial impact on the environment while imposing significant additional costs that will make drilling and operating such wells uneconomical.'' (James Elliott, Spilman Thomas & Battle, PLLC, on behalf of Independent Petroleum Association of America et al., August 8, 2014)

control be required when the following scenario exists:

> A well where the reservoir pressure is less than 0.4645 times the vertical depth of the deepest target reservoir.

At reservoir pressures below this value, the commenter contends that insufficient pressure exists for any gas to flow to a flare, enclosed combustion device or the process. Consequently, the commenter proposes that combustion through a flare or enclosed combustion device be required when the following scenario exists:

> A well where the reservoir pressure is less than 0.4645 times the vertical depth of the deepest target reservoir plus the gathering or sales line pressure.

At reservoir pressures less than the sum of the water column pressure and the sales line pressure, the commenter contended that the recovered gas will not naturally flow into the sales line. The commenter stated that the proposed rule does not require compression of recovered gas into the sales line. The commenter further states that the EPA has recognized this type of simpler approach in estimating the level of pressure necessary for recovered gas to flow into a gathering or sales line in their Gas STAR document cited above. In this Gas STAR paper, a table (Exhibit 5) is provided that shows the pressures necessary for various well depths. For instance, the commenter pointed out that the document indicates that the reservoir pressure necessary to flow recovered gas into a sales line for a 10,000-foot well would be 4,645 psig plus the sales line pressure.

Response: We agree with the commenters that ''true vertical depth'' is more accurate terminology that better represents our intent. Although we are not adopting the alternative definitions for the reasons presented above, we are amending the current definition of low pressure gas well to include ''true vertical depth.''

C. Storage Vessel Requirements

Comment: One commenter acknowledged the EPA's proposal to remove provisions relating to storage vessels ''installed in parallel'' or ''connected in parallel'' because these provisions ''inadvertently'' encompassed storage vessels the Agency did not intend to address. However, the commenter contended that the EPA does not identify those vessels that it believes were inadvertently covered in the December 2014 rule, nor does it propose alternative regulatory language that would ensure adequate control measures for vessels connected or installed in parallel that were intended to be covered under the December 2014 rule.

Given that storage vessels, including those installed or connected in parallel, can be significant sources of emissions, the commenter opposed the EPA's proposal to simply remove any provisions addressing these vessels. Instead of removing all provisions regarding vessels installed or connected in parallel, as the Agency proposed, the commenter urged the EPA to instead clarify its existing requirements for such vessels. The commenter suggested that the EPA could, for instance, clarify that pollution control measures apply to storage vessels operated in parallel in the relevant regulatory provisions addressing storage vessel affected facilities and the definitions of ''returned to service'' and ''storage vessel.''

Response: The change to the definition of ''storage vessel'' is intended to preserve the original basis on individual storage vessels to determine affected facility status, while addressing the potential situation where the flow of crude oil, condensate, intermediate hydrocarbon liquids, or produced water is divided into two or more tanks operated in parallel (*i.e.,* sharing the emissions at the correlated fraction of what a single tank would emit). Through comments submitted on the March 2015 proposed rule, the public has informed us that many storage vessels that are configured in parallel may not be operated or constructed to divide their potential to emit continuously, if ever. The EPA has now reconsidered our attempt to include storage vessels connected in parallel to address the specific situation resulting in circumvention. We believe that we do not have sufficient data to evaluate the scope of storage vessels that would fall under the amended definition and for which we did not intend to cover.

We believe that we have sufficient provisions under the General Provisions at 40 CFR 60.12 ''Circumvention'' to address the specific situation where storage vessels are divided into smaller tanks to avoid applicability of the rule and which was our intent with the previous amended definition. Therefore, we do not believe that our reverting to the prior definition of ''storage vessel'' will affect our ability to ensure control of these storage vessels. Consequently, as proposed, we are finalizing the removal of provisions made in the 2014 amendment relating to storage vessels ''installed in parallel'' or ''connected in parallel.''

V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.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 not a significant regulatory action and was, therefore, not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose an information collection burden under the PRA. OMB has previously approved the information collection requirements contained in the existing regulations and has assigned OMB control number 2060–0673. This action does not change the information collection requirements previously finalized and, as a result, does not impose any additional burden on industry.

C. 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. This action will not impose any requirements on small entities. This action is a reconsideration of an existing rule and imposes no new impacts or costs.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

E. 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.

F. 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 is a reconsideration of an existing rule and imposes no new impacts or costs. Thus, Executive Order 13175 does not apply to this action.

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

The EPA interprets Executive Order 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 Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

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

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

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations because it does not affect the level of protection provided to human health or the environment. This action is a reconsideration of an existing rule and imposes no new impacts or costs.

K. Congressional Review Act (CRA)

This action is subject to the 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

Administrative practice and procedure, Air pollution control, Environmental protection, Intergovernmental relations, Reporting and recordkeeping.

Dated: July 31, 2015.

Gina McCarthy,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended 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 Production, Transmission, and Distribution

■ 2. Section 60.5365(e)(4) is revised to read as follows:

§ 60.5365 Am I subject to this subpart?

* * * * *

(e) * * *

(4) For each new, reconstructed, or modified storage vessel with startup, startup of production, or which is returned to service, affected facility status is determined as follows: If a storage vessel is reconnected to the original source of liquids or is used to replace any storage vessel affected facility, it is a storage vessel affected facility subject to the same requirements as before being removed from service, or applicable to the storage vessel affected facility being replaced, immediately upon startup, startup of production, or return to service.

* * * * *

■ 3. Section 60.5430 is amended by revising the definitions for ''Low pressure gas well,'' ''Returned to service,'' and the first three sentences in the introductory text of ''Storage vessel'' to read as follows:

§ 60.5430 What definitions apply to this subpart?

* * * * *

Low pressure gas well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the true vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

* * * * *

Returned to service means that a Group 1 or Group 2 storage vessel affected facility that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility; or

(2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

* * * * *

Storage vessel means 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 nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of § 60.5395(f) until such time as such tank or other vessel has been returned to service. * * *

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[FR Doc. 2015–19733 Filed 8–11–15; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

42 CFR Part 84

[Docket Number CDC–2015–0004; NIOSH–280]

RIN 0920–AA60

Closed-Circuit Escape Respirators; Extension of Transition Period

AGENCY: Centers for Disease Control and Prevention, HHS.

ACTION: Final rule.

SUMMARY: In March 2012, the Department of Health and Human Services (HHS) published a final rule establishing a new standard for the certification of closed-circuit escape respirators (CCERs) by the National Institute for Occupational Safety and Health (NIOSH) within the Centers for Disease Control and Prevention (CDC). The new standard was originally designed to take effect over a 3-year transition period. HHS has determined that extending the concluding date for the transition is necessary to allow sufficient time for respirator manufacturers to meet the demands of the mining, maritime, railroad and other industries. Pursuant to this final action, NIOSH extends the phase-in period until 1 year after the date that the first approval is granted to certain CCER models.

DATES: This rule is effective on August 12, 2015.

FOR FURTHER INFORMATION CONTACT: Rachel Weiss, Program Analyst; 1090 Tusculum Avenue, MS: C–46, Cincinnati, OH 45226; telephone (855) 818–1629 (this is a toll-free number); email *NIOSHregs@cdc.gov.*

SUPPLEMENTARY INFORMATION:

NATIONAL ARCHIVES AND RECORDS ADMINISTRATION
1985

FEDERAL REGISTER

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Part II

Environmental Protection Agency

40 CFR Parts 60 and 63
Phosphoric Acid Manufacturing and Phosphate Fertilizer Production RTR and Standards of Performance for Phosphate Processing; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2012–0522; FRL–9931–01–OAR]

RIN 2060–AQ20

Phosphoric Acid Manufacturing and Phosphate Fertilizer Production RTR and Standards of Performance for Phosphate Processing

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes the residual risk and technology review conducted for the Phosphoric Acid Manufacturing and Phosphate Fertilizer Production source categories regulated under national emission standards for hazardous air pollutants (NESHAP). In addition, this action finalizes an 8-year review of the current new source performance standards (NSPS) for five source categories. We are also taking final action addressing Clean Air Act (CAA) provisions related to emission standards for hazardous air pollutants, review and revision of emission standards, and work practice standards. The final amendments to the Phosphoric Acid Manufacturing NESHAP include: Numeric emission limits for previously unregulated mercury (Hg) and total fluoride emissions from calciners; work practice standards for hydrogen fluoride (HF) emissions from previously unregulated gypsum dewatering stacks and cooling ponds; clarifications to the applicability and monitoring requirements to accommodate process equipment and technology changes; removal of the exemptions for startup, shutdown, and malfunction (SSM); adoption of work practice standards for periods of startup and shutdown; and revised recordkeeping and reporting requirements for periods of SSM. The final amendments to the Phosphate Fertilizer Production NESHAP include: Clarifications to the applicability and monitoring requirements to accommodate process equipment and technology changes; removal of the exemptions for SSM; adoption of work practice standards for periods of startup and shutdown; and revised recordkeeping and reporting requirements for periods of SSM. The revised NESHAP for Phosphoric Acid Manufacturing facilities will mitigate future increases of Hg emissions from phosphate rock calciners by requiring pollution prevention measures. Further, based on the 8-year review of the current NSPS for these source categories, the EPA determined that no revisions to the numeric emission limits in those rules are warranted.

DATES: This final action is effective on August 19, 2015. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of August 19, 2015.

ADDRESSES: The Environmental Protection Agency (EPA) has established a docket for this action under Docket ID No. EPA–HQ–OAR–2012–0522. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, 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 either electronically through *http://www.regulations.gov,* or in hard copy at the EPA Docket Center, EPA 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 Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact Dr. Tina Ndoh, Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, 27711; telephone number: (919) 541–2750; fax number: (919) 541–5450; and email address: *Ndoh.Tina@epa.gov.* For specific information regarding the risk modeling methodology, contact James Hirtz, Health and Environmental Impacts Division (C539–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–0881; fax number: (919) 541–0359; and email address: *Hirtz.James@epa.gov.* For information about the applicability of the NESHAP or NSPS to a particular entity, contact Scott Throwe, Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, EPA WJC, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 562–7013; and email address: *Throwe.Scott@epa.gov.*

SUPPLEMENTARY INFORMATION: *Preamble Acronyms and Abbreviations.* 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:

ACI	Activated carbon injection
AEGL	Acute exposure guideline levels
AFPC	Association of Fertilizer and Phosphate Chemists
AOAC	Association of Official Analytical Chemists
BACT	Best available control technology
BSER	Best System of Emissions Reduction
BTF	Beyond the floor
CAA	Clean Air Act
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
CMS	Continuous monitoring system
CPMS	Continuous parameter monitoring system
DAP	Diammonium phosphate
DOE	Department of Energy
EPA	Environmental Protection Agency
ERT	Electronic Reporting Tool
FR	Federal Register
FTIR	Fourier transform infrared spectroscopy
GMCS	Gore Mercury Control System
GTSP	Granular triple superphosphate
HAP	Hazardous air pollutants
HF	Hydrogen fluoride
Hg	Mercury
HI	Hazard index
HQ	Hazard quotient
ICR	Information Collection Request
LAER	Lowest achievable emissions rate
lb/MMBtu	Pounds per million Btu
LOAEL	Lowest-observed-adverse-effect level
MACT	Maximum achievable control technology
MAP	Monoammonium phosphate
mg/dscm	Milligrams per dry standard cubic meter
MIBK	Methyl isobutyl ketone
MIR	Maximum individual risk
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NAS	National Academy of Sciences
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory
NOAEL	No-observed-adverse-effect level
NSPS	New source performance standard
NTTAA	National Technology Transfer and Advancement Act
OAQPS	Office of Air Quality Planning and Standards
OMB	Office of Management and Budget
P_2O_5	Phosphorus pentoxide
PAC	Powdered activated carbon

PB–HAP	Hazardous air pollutants known to be persistent and bio-accumulative in the environment
PM	Particulate matter
POM	Polycyclic organic matter
PPA	Purified phosphoric acid
ppm	Parts per million
RACT	Reasonably available control technology
RBLC	RACT/BACT/LAER Clearinghouse
REL	Reference exposure level
RFA	Regulatory Flexibility Act
RTR	Residual risk and technology review
SBA	Small Business Administration
SiF4	Silicon tetrafluoride
SPA	Superphosphoric acid
SSM	Startup, shutdown, and malfunction
TOSHI	Target organ-specific hazard index
tpy	Tons per year
TRIM	Total Risk Integrated Modeling System
TRIM.FaTE	Total Risk Integrated Methodology.Fate, Transport, and Ecological Exposure model
TSP	Triple superphosphates
TTN	Technology Transfer Network
UMRA	Unfunded Mandates Reform Act
UPL	Upper prediction limit
VCS	Voluntary consensus standards
WESP	Wet electrostatic precipitator
WPPA	Wet-process phosphoric acid
WWW	World Wide Web

Background Information. On November 7, 2014 (79 FR 66511), the EPA proposed revisions to the Phosphoric Acid Manufacturing and Phosphate Fertilizer Production national emission standards for hazardous air pollutants (NESHAP) in conjunction with the residual risk and technology review (RTR) for those NESHAP, 40 CFR part 63, subparts AA and BB, and required 8-year review of the Standards of Performance for the Phosphate Fertilizer Industry new source performance standards (NSPS) for 40 CFR part 60, subparts T, U, V, W and X. In this action, we are finalizing decisions and revisions for the rules. We summarize some of the more significant comments we received regarding the proposed rule and provide our responses in this preamble. A summary of all other public comments on the proposal and the EPA's responses to those comments is available in ''Phosphoric Acid Manufacturing and Phosphate Fertilizer Production RTR and Standards of Performance for Phosphate Processing—Summary of Public Comments and Responses'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522. A ''track changes'' version of the regulatory language that incorporates the changes in this action for each NSPS is available in the docket. The NESHAP were replaced in their entirety to assist in readability of the language and to ensure that citations were accurate.

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

Significantly Affect Energy Supply, Distribution or Use
I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. General Information

A. Does this action apply to me?

Regulated Entities. Categories and entities potentially regulated by this action are shown in Table 1 of this preamble.

TABLE 1—NESHAP AND INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS FINAL ACTION

NESHAP and source category	NAICS [a] code
Phosphoric Acid Manufacturing Phosphate Fertilizer Production	325312

[a] North American Industry Classification System.

Table 1 of this preamble is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by the final action for the source category listed. To determine whether your facility is affected, you should examine the applicability criteria in the appropriate NESHAP. If you have any questions regarding the applicability of any aspect of this NESHAP, please contact the appropriate person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section of this preamble.

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 will also be available on the Internet through the Technology Transfer Network (TTN) Web site, a forum for information and technology exchange in various areas of air pollution control. Following signature by the EPA Administrator, the EPA will post a copy of this final action at *http://www.epa.gov/ttn/atw/phosph/phosphpg.html.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version and key technical documents at this same Web site.

Additional information is available on the RTR Web site at *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html.* This information includes an overview of the RTR program, links to project Web sites for the RTR source categories and detailed emissions and other data we used as inputs to the risk assessments.

C. Judicial Review and Administrative Reconsideration

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 (U.S.) Court of Appeals for the District of Columbia Circuit by October 19, 2015. 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.

Section 307(d)(7)(B) of the CAA 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 reconsider the rule ‘‘[i]f the person raising an objection can demonstrate to the Administrator 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 should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, EPA WJC 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. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Background

A. What is the statutory authority for this action?

1. NESHAP Authority

Section 112 of the CAA establishes a two-stage regulatory process to address emissions of hazardous air pollutants (HAP) from stationary sources. In the first stage, we must identify categories of sources emitting one or more of the HAP listed in CAA section 112(b) and then promulgate technology-based NESHAP for those sources. ‘‘Major sources’’ are those that emit, or have the potential to emit, any single HAP at a rate of 10 tons per year (tpy) or more, or 25 tpy or more of any combination of HAP. For major sources, these standards are commonly referred to as maximum achievable control technology (MACT) standards and must reflect the maximum degree of emission reductions of HAP achievable (after considering cost, energy requirements, and non-air quality health and environmental impacts). In developing MACT standards, CAA section 112(d)(2) directs the EPA to consider the application of measures, processes, methods, systems or techniques, including, but not limited to those that reduce the volume of or eliminate HAP emissions through process changes, substitution of materials, or other modifications; enclose systems or processes to eliminate emissions; collect, capture, or treat HAP when released from a process, stack, storage, or fugitive emissions point; are design, equipment, work practice, or operational standards; or any combination of the above.

For these MACT standards, the statute specifies certain minimum stringency requirements, which are referred to as MACT floor requirements, and which may not be based on cost considerations. See CAA section 112(d)(3). For new sources, the MACT floor cannot be less stringent than the emission control achieved in practice by the best-controlled similar source. The MACT standards for existing sources can be less stringent than floors for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources). In developing MACT standards, we must also consider control options that are more stringent than the floor, under CAA section 112(d)(2). We may establish standards more stringent than the floor, based on the consideration of the cost of achieving the emissions reductions, any non-air quality health and environmental impacts, and energy requirements.

In the second stage of the regulatory process, the CAA requires the EPA to undertake two different analyses, which we refer to as the technology review and the residual risk review. Under the technology review, we must review the technology-based standards and revise them ‘‘as necessary (taking into account developments in practices, processes, and control technologies)’’ no less frequently than every 8 years, pursuant to CAA section 112(d)(6). Under the residual risk review, we must evaluate the risk to public health remaining after application of the technology-based standards and revise the standards, if necessary, to provide an ample margin of safety to protect public health or to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect. The residual risk review is required within 8 years after promulgation of the technology-based standards, pursuant to CAA section 112(f). In conducting the residual risk review, if the EPA determines that the current standards provide an ample margin of safety to protect public health, it is not necessary to revise the MACT standards pursuant to CAA section 112(f).[1] For more information on the statutory authority for this rule, see 79 FR 66512 (November 7, 2014).

2. NSPS Authority

NSPS implement CAA section 111, which requires that each NSPS reflect the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) which (taking into consideration the cost of achieving such emission reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Existing affected facilities that are modified or reconstructed are also subject to NSPS. 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.

Rebuilt emission units would become subject to the NSPS under the reconstruction provisions in 40 CFR 60.15, regardless of changes in emission rate. 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 (40 CFR 60.15).

Section 111(b)(1)(B) of the CAA requires the EPA to periodically review and, if appropriate, revise the standards of performance as necessary to reflect improvements in methods for reducing emissions. The EPA need not review an NSPS if the Agency determines that such review is not appropriate in light of readily available information on the efficacy of the standard. When conducting the review under CAA section 111(b)(1)(B), the EPA considers both: (1) Whether developments in technology or other factors support the conclusion that a different system of emissions reduction has become the BSER and (2) whether emissions limitations and percent reductions beyond those required by the current standards are achieved in practice.

B. What are the Phosphoric Acid Manufacturing and Phosphate Fertilizer Production source categories and how do the NESHAP and NSPS regulate emissions from these source categories?

1. Description of Phosphoric Acid Manufacturing Source Category

In 2014, 12 facilities in the U.S. manufactured phosphoric acid. The basic step for producing phosphoric acid is acidulation of phosphate rock. Typically, sulfuric acid, phosphate rock, and water are combined together and allowed to react to produce phosphoric acid and gypsum. When phosphate rock is acidulated to manufacture wet-process phosphoric acid (WPPA), fluorine contained in the rock is released. Fluoride compounds, predominately HF, are produced as particulates and gases that are emitted to the atmosphere unless removed from the exhaust stream. Some of these same fluoride compounds also remain in the product acid and are released as air pollutants during subsequent processing of the acid. Gypsum is pumped as a slurry to ponds atop stacks of waste gypsum where the liquids separate from the slurry and are decanted for return to the process. The gypsum, which is discarded on the stack, is a solid waste stream produced in this process. Five facilities concentrate WPPA to make superphosphoric acid (SPA), typically using the vacuum evaporation process. While one manufacturer is permitted to use a submerged combustion process for the production of SPA, that process was indefinitely shutdown on June 1, 2006. The majority of WPPA is used to produce phosphate fertilizers.

Additional processes may also be used to further refine phosphoric acid. At least two facilities have a defluorination process to remove fluorides from the phosphoric acid product, and one company uses a solvent extraction process to remove metals and organics and to further refine WPPA into purified phosphoric acid (PPA) for use in food manufacturing or specialized chemical processes. In addition, four facilities have oxidation processes to remove organics from the acid (*i.e.,* the green acid process). One of these facilities also calcines the ore prior to the acidulation process to help achieve the desired organic content reduction for the final acid product.

Sources of HF emissions from phosphoric acid plants include gypsum dewatering stacks, cooling ponds, cooling towers, calciners, reactors, filters, evaporators and other process equipment.

2. Federal Air Emission Standards Applicable to the Phosphoric Acid Manufacturing Source Category

The following federal air emission standards are associated with the Phosphoric Acid Manufacturing source category and are the subject of this final action:

- National Emission Standards for Hazardous Air Pollutants from Phosphoric Acid Manufacturing Plants (40 CFR part 63, subpart AA);
- Standards of Performance for the Phosphate Fertilizer Industry: Wet-Process Phosphoric Acid Plants (40 CFR part 60, subpart T); and
- Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants (40 CFR part 60, subpart U).

a. Phosphoric Acid Manufacturing NESHAP Emission Regulations. The EPA promulgated 40 CFR part 63, subpart AA for the Phosphoric Acid Manufacturing source category on June 10, 1999 (64 FR 31358). The NESHAP established standards for major sources to control HAP emissions from phosphoric acid facilities. Total fluoride emission limits, as a surrogate for the HAP HF, were set for WPPA process lines and SPA process lines. The NESHAP established emission limits for particulate matter (PM) from phosphate rock dryers and phosphate rock calciners as a surrogate for metal HAP. Also, the NESHAP established an emission limit for methyl isobutyl ketone (MIBK) for PPA process lines and work practices for cooling towers. For more information on this NESHAP, see 79 FR 66512.

b. Phosphoric Acid Manufacturing NSPS Emission Regulations. The EPA promulgated 40 CFR part 60, subpart T for WPPA Plants on August 6, 1975 (40 FR 33154). The NSPS established standards to control total fluoride emissions from WPPA plants, including

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[1] The U.S. Court of Appeals has affirmed this approach of implementing CAA section 112(f)(2)(A): *NRDC* v. *EPA,* 529 F.3d 1077, 1083 (D.C. Cir. 2008) (''If EPA determines that the existing technology-based standards provide an 'ample margin of safety,' then the Agency is free to readopt those standards during the residual risk rulemaking.'').

reactors, filters, evaporators, and hot wells.

The EPA promulgated 40 CFR part 60, subpart U for SPA Plants on August 6, 1975 (40 FR 33155). The NSPS established standards to control total fluoride emissions from SPA plants, including evaporators, hot wells, acid sumps, and cooling tanks.

For more information on these NSPS, see 79 FR 66512.

3. Description of Phosphate Fertilizer Production Source Category

There are 11 operating facilities that produce phosphate fertilizers, and most facilities have the ability to produce either monoammonium phosphates (MAP) or diammonium phosphates (DAP) in the same process train. However, approximately 80 percent of all ammonium phosphates are produced as MAP. MAP and DAP plants are generally collocated with WPPA plants since both are manufactured from phosphoric acid and ammonia. The MAP and DAP manufacturing process consists of three basic steps: Reaction, granulation, and finishing operations such as drying, cooling, and screening. Sources of fluoride emissions from MAP and DAP plants include the reactor, granulator, dryer, cooler, screens, and mills. Some of the fluoride is liberated as HF and silicon tetrafluoride (SiF_4), but the majority is emitted as HF.

Triple superphosphates (TSP) are made as run-of-pile TSP (ROP–TSP) and granular TSP (GTSP) by reacting WPPA with ground phosphate rock. The phosphoric acid used in the GTSP process is appreciably lower in concentration (40-percent phosphorus pentoxide (P_2O_5)) than that used to manufacture ROP–TSP product (50 to 55-percent P_2O_5). The GTSP process yields larger, more uniform particles with improved storage and handling properties than the ROP–TSP process. Currently, no facilities produce ROP–TSP or GTSP,[2] although one facility retains an operating permit to store GTSP.

4. Federal Air Emission Standards Applicable to the Phosphate Fertilizer Production Source Category

The following federal air emission standards are associated with the Phosphate Fertilizer Production source category and are subject of this final action:

- National Emission Standards for Hazardous Air Pollutants from Phosphate Fertilizers Production Plants (40 CFR part 63, subpart BB);
- Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants (40 CFR part 60, subpart V);
- Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants (40 CFR part 60, subpart W); and
- Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities (40 CFR part 60, subpart X).

a. Phosphate Fertilizer Production NESHAP Emission Regulations. The EPA promulgated 40 CFR part 63, subpart BB for the Phosphate Fertilizer Production source category on June 10, 1999 (64 FR 31358). The NESHAP established standards for major sources to control HAP emissions from phosphate fertilizer facilities. As a surrogate for HF, the NESHAP set total fluoride emission limits for DAP and/or MAP process lines and GTSP process lines and storage buildings. The NESHAP also established work practices for GTSP production. For more information on this NESHAP, see 79 FR 66512.

b. Phosphate Fertilizer Production NSPS Emission Regulations. The EPA promulgated 40 CFR part 60, subpart V for Diammonium Phosphate Plants on July 25, 1977 (42 FR 37938). The NSPS established standards to control total fluoride emissions from granular DAP plants, including reactors, granulators, dryers, coolers, screens, and mills.

The EPA promulgated 40 CFR part 60, subpart W for TSP plants on July 25, 1977 (42 FR 37938). The NSPS established standards to control total fluoride emissions from the production of ROP–TSP and GTSP, and the storage of ROP–TSP.

The EPA promulgated 40 CFR part 60, subpart X for GTSP storage facilities on July 25, 1977 (42 FR 37938). The NSPS established standards to control total fluoride emissions from the storage of GTSP, including storage or curing buildings (noted as ‘‘piles’’ in subpart X), conveyors, elevators, screens, and mills.

For more information on these NSPS, see 79 FR 66512.

C. What changes did we propose for the Phosphoric Acid Manufacturing and Phosphate Fertilizer Production source categories in our November 7, 2014 proposal?

On November 7, 2014 (79 FR 66512), the EPA published a proposed rule in the **Federal Register** for both the Phosphoric Acid Manufacturing NESHAP, 40 CFR part 63, subpart AA, and Phosphate Fertilizer Production NESHAP, 40 CFR part 63, subpart BB that took into consideration the RTR analyses. We also proposed other revisions to these NESHAP. In the proposed rule, we proposed:

For Phosphoric Acid Manufacturers:

- Numeric emission limits for Hg and work practice standards for HF from calciners; and
- Work practice standards for HF emissions from gypsum dewatering stacks and cooling ponds.

For both Phosphoric Acid Manufacturers and Phosphate Fertilizer Producers:

- Emission limits regulating HF emissions as the target HAP (HF), instead of the long-standing surrogate for HF, total F;
- Clarifications to applicability and certain definitions;
- Revisions to requirements related to emissions during periods of SSM;
- Revisions to monitoring requirements for absorbers;
- Requirements for reporting of performance testing through the electronic reporting tool (ERT);
- Modification to the format to reference tables for emissions limits and monitoring requirements; and
- Several minor clarifications and corrections.

In addition, we proposed revisions to the NSPS subparts T, U, V, W, and X, including clarifications to applicability and certain definitions, and revisions to monitoring and recordkeeping requirements for absorbers.

III. What is included in this final rule for the Phosphoric Acid Manufacturing source category?

This action finalizes the EPA's determinations pursuant to the RTR provisions of CAA section 112 and the 8-year review provisions of CAA section 111 for the Phosphoric Acid Manufacturing source category. Today's action also finalizes several of the proposed changes to the NESHAP subpart AA and the NSPS subparts T and U that are described in section II.C. of this preamble. This action also finalizes other changes to the NESHAP subpart AA in consideration of comments on issues raised in the proposed rulemaking, as described in section V of this preamble.

A. What are the final rule amendments based on the NESHAP residual risk review for the Phosphoric Acid Manufacturing source category?

The residual risk review for the Phosphoric Acid Manufacturing source category did not change since proposal; we found that the current standards provide an ample margin of safety to protect public health (79 FR 66512) and prevent an adverse environmental effect. We are, therefore, not tightening the standards under section 112(f)(2)

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[2] According to 2014 production and trade statistics issued by International Fertilizer Industry Association (IFA).

(for NESHAP subpart AA) based on the residual risk review, and are thus readopting the existing standards under section 112(f)(2). See sections V.A.3 and V.A.4 of this preamble for discussion on key comments and responses regarding the residual risk review.

B. What are the final rule amendments based on the NESHAP technology review for the Phosphoric Acid Manufacturing source category?

The technology review for the Phosphoric Acid Manufacturing source category did not change since proposal (79 FR 66512). We determined that there are no cost-effective developments in practices, processes, and control technologies that warrant revisions to the MACT standards for this source category (79 FR 66512). Therefore, we are not amending the MACT standards under CAA section 112(d)(6). See sections V.B.3 and V.B.4 of this preamble for discussion on key comments and responses regarding the technology review.

C. What are the final rule amendments pursuant to CAA sections 112(d)(2), 112(d)(3), and 112(h) for the Phosphoric Acid Manufacturing source category?

We are finalizing MACT standards for HF and Hg pursuant to CAA sections 112(d)(2) and 112(d)(3) for phosphate rock calciners, an emissions source that was initially regulated for HAP metals using PM as a surrogate. Specifically, we are finalizing, as proposed, the elimination of the use of PM as a surrogate for Hg; however, we are making changes to the proposed Hg emission limit for phosphate rock calciners in NESHAP subpart AA to reflect MACT floor level emission standards for existing sources. We are finalizing the proposed beyond-the-floor (BTF) emission standard for Hg emissions from new phosphate rock calciners. We discuss the changes to the Hg emission limit in section V.C.3.a.i of this preamble. In addition, we are finalizing, as proposed, to retain the PM standard as a surrogate for other HAP metal emissions from phosphate rock calciners. However, in consideration of comments received during the public comment period for the proposed rulemaking, we are not finalizing work practice standards for HF from phosphate rock calciners, as proposed. Instead, as discussed in section V.C.3.a.ii of this preamble, we are including a total fluoride emission limit for phosphate rock calciners in NESHAP subpart AA.

Also, in consideration of comments received (see section V.C.3.b.i of this preamble for details), we are not adopting the proposed work practice in NESHAP subpart AA that would limit the size of active gypsum dewatering stacks (which would have been applicable to facilities when new gypsum dewatering stacks are constructed). Lastly, we are finalizing work practice standards pursuant to CAA section 112(h) for gypsum dewatering stacks and cooling ponds—emissions sources that were not regulated under the initial MACT standard. Specifically, we are finalizing in NESHAP subpart AA, as proposed, the work practice standard that requires owners or operators to prepare and operate in accordance with a gypsum dewatering stack and cooling pond management plan. However, based on analysis of public comments, we are making several changes to the specific control techniques that we proposed as options in the plan for controlling fugitive HF emissions (see section V.C.3.b.ii of this preamble for details on these changes). In the final rule, the Agency is using the terminology ‘‘control measures’’ in lieu of the proposed terminology ‘‘control techniques’’ because we feel this more accurately describes the list of options in the rule and avoids confusion with other CAA programs.

D. What are the final rule amendments based on the NSPS review for the Phosphoric Acid Manufacturing source category?

We are finalizing our determination that revisions to NSPS subpart T and subpart U standards are not appropriate pursuant to CAA section 111(b)(1)(B). All Phosphoric Acid Manufacturing NSPS (under subpart T and subpart U) emission sources, and the control technologies that would be employed, are the same as those for the NESHAP regulating phosphoric acid plants, such that we reached the same determination that there are no identified cost-effective practices or technologies that would provide additional emission reductions. Additionally, there were no identified technologies that have been adequately demonstrated to achieve in practice emission controls that would result in more stringent total fluoride limits for these NSPS. See section V.D of this preamble for discussion on key comments and responses regarding the NSPS review.

E. What are the final rule amendments addressing emissions during periods of startup, shutdown, and malfunction for the Phosphoric Acid Manufacturing source category?

We are finalizing, as proposed, changes to the Phosphoric Acid Manufacturing NESHAP, subpart AA to eliminate the SSM exemption. 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. Appendix A of subpart AA (the General Provisions Applicability Table) is being revised to change several references related to requirements that apply during periods of SSM. We also eliminated or revised certain recordkeeping and reporting requirements related to the eliminated SSM exemption. The EPA also made changes to the rule to remove or modify inappropriate, unnecessary, or redundant language in the absence of the SSM exemption. For this source category, we determined that work practice standards for periods of startup and shutdown are appropriate in lieu of numeric emission limits due to the short duration of startup and shutdown, and control devices used on the various process lines in this source category are effective at achieving desired emission reductions immediately upon startup (79 FR 66541). Therefore, we are finalizing in NESHAP subpart AA the proposed work practice standards for periods of startup and shutdown. However, in consideration of comments received during the public comment period, we are making changes to the work practice standards in order to clarify that the standard applies in lieu of numeric emission limits and how compliance with the standard is demonstrated. In order to comply with the work practice standard, facilities must monitor the same control device operating parameters and comply with the same operating limits that are established to otherwise comply with the emission limits. Additionally, we added a definition of ‘‘startup’’ and ‘‘shutdown’’ in the definitions section of the final rule to specify when startup begins and ends, and when shutdown begins and ends. See section V.E.3 of this preamble for details on these changes.

F. What other changes are we making to the NESHAP and NSPS for the Phosphoric Acid Manufacturing source category?

Today’s rule also finalizes, as proposed, revisions to several other Phosphoric Acid Manufacturing NESHAP and NSPS requirements. We are finalizing, as proposed, several miscellaneous changes to clarify applicability and certain definitions, as follows:

- Adopting the proposed SPA process line definition in NESHAP subpart AA to include oxidation reactors;

- Adopting the proposed SPA plant definition in NSPS subpart U to include oxidation reactors;
- Finalizing the proposed revisions to rename ''gypsum stack'' to ''gypsum dewatering stack'' in NESHAP subpart AA; and
- Finalizing the proposed definitions for ''cooling pond'' and ''raffinate stream'' in NESHAP subpart AA.

We are finalizing, as proposed, several changes to testing, monitoring, recordkeeping and reporting requirements to provide consistency, clarification and flexibility, as follows:

- Finalizing the proposed revisions to NESHAP subpart AA that require a minimum pressure drop of 5 inches of water column for facilities that use pressure differential in parametric monitoring;
- Finalizing the proposal to remove the requirement in NESHAP subpart AA that facilities must request and obtain approval of the Administrator for changing operating limits;
- Adopting the proposed addition of a site-specific monitoring plan and calibration requirements for a continuous monitoring system (CMS) in NESHAP subpart AA;
- Adopting the proposed term ''absorber'' in lieu of ''scrubber'' in NESHAP subpart AA;
- Adopting the proposed format of NESHAP subpart AA to reference tables for emissions limits and monitoring requirements;
- Adopting the proposed provisions in NSPS subpart T and NSPS subpart U that require the owner or operator to establish an allowable range for the pressure drop through the process scrubbing system, keep records of the daily average pressure drop through the process scrubbing system, and keep records of deviations; and
- Adopting the proposed term ''absorber'' in lieu of ''process scrubbing system'' in NSPS subpart T and NSPS subpart U.

We are also finalizing changes to the NESHAP and NSPS for the Phosphoric Acid Manufacturing source category on issues raised in response to the proposed rulemaking, as follows (refer to section V.F.2 of this preamble for further details):

- Revising the definition of oxidation reactor in the final rule for NESHAP subpart AA and NSPS subpart U;
- Finalizing liquid-to-gas ratio monitoring in NESHAP subpart AA for low-energy absorbers (*i.e.,* absorbers that are designed to operate with pressure drops of 5 inches of water column or less) in lieu of monitoring influent liquid flow and pressure drop through the absorber;
- Clarifying in NESHAP subpart AA that during the most recent performance test, if owners or operators demonstrate compliance with the emission limit while operating their control device outside the previously established operating limit, owners or operators must establish a new operating limit based on that most recent performance test and notify the Administrator that the operating limit changed based on data collected during the most recent performance test; and
- Clarifying in NESHAP subpart AA that facilities not be required to obtain approval, and, instead, immediately comply with a new operating limit when it is developed and submitted to the Administrator.

G. What are the effective and compliance dates of the standards for the Phosphoric Acid Manufacturing source category?

The revisions to the NSPS and NESHAP standards we promulgate in this action for the Phosphoric Acid Manufacturing source category are effective on August 19, 2015.

The compliance date for the Hg limit in NESHAP subpart AA for existing phosphate rock calciners is August 19, 2015. Based on the data that the EPA has received, all existing phosphate rock calciners are meeting the Hg limit; therefore, no additional time would be required to achieve compliance with this standard.

The compliance date for the Hg limit in NESHAP subpart AA for new phosphate rock calciners is August 19, 2015, or upon startup, whichever is later. We are not aware of any new phosphate rock calciners operating today. New phosphate rock calciners that commence construction or reconstruction after the effective date of this rule would be required to comply with the Hg limits immediately upon startup.

The compliance date for the total fluoride limits in NESHAP subpart AA for all (existing and new) phosphate rock calciners is August 19, 2015, or upon startup, whichever is later. Based on the data that the EPA has received, all phosphate rock calciners are meeting the total fluoride limit; therefore, no additional time would be required to achieve compliance with this standard.

The compliance date in NESHAP subpart AA for preparing and operating in accordance with a gypsum dewatering stack and cooling pond management plan is August 19, 2016. A 1-year compliance lead-time will provide facilities adequate time to prepare and submit their plan for approval to the Administrator.

The compliance date for when facilities must include oxidation reactors in determining compliance with the total fluoride limit in NESHAP subpart AA for SPA process lines is August 19, 2016. We believe that 1 year is necessary because a facility may need to install additional control technology. A 1-year compliance period will provide the facility adequate time to design and install controls.

The compliance date in NESHAP subpart AA for when to install, calibrate, and maintain a bag leak detection system on a fabric filter is August 19, 2016. We believe that 1 year is necessary because some facilities that currently operate a fabric filter do not have a bag leak detection system and will need time to purchase and install this compliance monitoring equipment and implement quality assurance measures.

The compliance date in NESHAP subpart AA for the revised startup and shutdown requirements is August 19, 2015. We determined that the feasibility of operating the control devices used to control HAP emissions from phosphoric acid manufacturing is not limited by specific process operating conditions.

Finally, to ensure continuous compliance with the standard, the compliance date for the monitoring and recordkeeping requirements in NSPS subparts T and U for all new WPPA plants and SPA plants is August 19, 2015, or upon startup, whichever is later.

H. What are the requirements for submission of performance test data to the EPA for the Phosphoric Acid Manufacturing source category?

As stated in the preamble to the proposed rule, the EPA is taking a step to increase the ease and efficiency of data submittal and data accessibility. Specifically, the EPA is requiring owners and operators of phosphoric acid facilities to submit electronic copies of certain required performance test reports.

As mentioned in the preamble of the proposal, data will be collected by direct computer-to-computer electronic transfer using EPA-provided software. As discussed in the proposal, the EPA-provided software is an electronic performance test report tool called the ERT. The ERT will generate an electronic report package which will be submitted to the Compliance and Emissions Data Reporting Interface (CEDRI) and then archived to the EPA's Central Data Exchange (CDX). A description and instructions for use of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/index.html,* and CEDRI can be accessed through the CDX Web site at *www.epa.gov/cdx.*

The requirement to submit performance test data electronically to the EPA does not create any additional performance testing and will apply only to those performance tests conducted using test methods that are supported by the ERT. A listing of the pollutants and test methods supported by the ERT is available at the ERT Web site. The EPA believes, through this approach, industry will save time in the performance test submittal process. Additionally, this rulemaking benefits industry by cutting back on recordkeeping costs as the performance test reports that are submitted to the EPA using CEDRI are no longer required to be kept in hard copy.

As mentioned in the proposed preamble, state, local, and tribal agencies will benefit from more streamlined and accurate review of performance test data that will be available on the EPA WebFIRE database. The public will also benefit. Having these data publicly available enhances transparency and accountability. For a more thorough discussion of electronic reporting of performance tests using direct computer-to-computer electronic transfer and using EPA-provided software, see the discussion in the preamble of the proposal.

In summary, in addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with performance test data will save industry, state, local, and tribal agencies, and the EPA significant time, money, and effort, while improving the quality of emission inventories, air quality regulations, and enhancing the public's access to this important information.

IV. What is included in this final rule for the Phosphate Fertilizer Production source category?

This action finalizes the EPA's determinations pursuant to the RTR provisions of CAA section 112 and the 8-year review provisions of CAA section 111 for the Phosphate Fertilizer Production source category. Today's action also finalizes several of the proposed changes to the NESHAP subpart BB and the NSPS subparts V, W, and X that are described in section II.C of this preamble. This action also finalizes other changes to the NESHAP subpart BB in consideration of comments on issues raised in the proposed rulemaking, as described in section VI of this preamble.

A. What are the final rule amendments based on the NESHAP risk review for the Phosphate Fertilizer Production source category?

The residual risk review for the Phosphate Fertilizer Production source category did not change since proposal; we found that the current standards provide an ample margin of safety to protect public health (79 FR 66512) and prevent an adverse environmental effect. We are, therefore, not tightening the standards under section 112(f)(2) (for NESHAP subpart BB) based on the residual risk review, and are thus readopting the existing standards under section 112(f)(2).

B. What are the final rule amendments based on the NESHAP technology review for the Phosphate Fertilizer Production source category?

The technology review for the Phosphate Fertilizer Production source category did not change since proposal (79 FR 66512). We determined that there are no cost-effective developments in practices, processes, and control technologies that warrant revisions to the MACT standards for this source category (79 FR 66512). Therefore, we are not amending the MACT standards under CAA section 112(d)(6).

C. What are the final rule amendments based on the NSPS review for the Phosphate Fertilizer Production source category?

We are finalizing our determination that revisions to NSPS subpart V, subpart W, and subpart X standards are not appropriate pursuant to CAA section 111(b)(1)(B). All Phosphate Fertilizer Production NSPS (under subpart V, subpart W, and subpart X) emission sources, and the control technologies that would be employed, are the same as those for the NESHAP regulating phosphate fertilizer plants, such that we reached the same determination that there are no identified cost-effective practices or technologies that would provide additional emission reductions. Additionally, there were no identified technologies that have been adequately demonstrated to achieve in practice emission controls that would result in more stringent total fluoride limits for these NSPS.

D. What are the final rule amendments addressing emissions during periods of startup, shutdown, and malfunction for the Phosphate Fertilizer Production source category?

We are finalizing, as proposed, changes to the Phosphate Fertilizer Production NESHAP, subpart BB to eliminate the SSM exemption. 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. Appendix A of subpart BB (the General Provisions Applicability Table) is being revised to change several references related to requirements that apply during periods of SSM. We also eliminated or revised certain recordkeeping and reporting requirements related to the eliminated SSM exemption. The EPA also made changes to the rule to remove or modify inappropriate, unnecessary, or redundant language in the absence of the SSM exemption. For this source category, we determined that work practice standards for periods of startup and shutdown are appropriate in lieu of numeric emission limits due to the short duration of startup and shutdown, and control devices used on the various process lines in this source category are effective at achieving desired emission reductions immediately upon startup (79 FR 66551). Therefore, we are finalizing in NESHAP subpart BB the proposed work practice standards for periods of startup and shutdown. However, in consideration of comments received during the public comment period, we are making changes to the work practice standards in order to clarify that the standard applies in lieu of numeric emission limits and how compliance with the standard is demonstrated. In order to comply with the work practice standard, facilities must monitor the same control device operating parameters and comply with the same operating limits that are established to otherwise comply with the emission limits. Additionally, we added a definition of ''startup'' and ''shutdown'' in the definitions section of the final rule to specify when startup begins and ends, and when shutdown begins and ends. See section VI.D.3 of this preamble for details on these changes.

E. What other changes are we making to the NESHAP and NSPS for the Phosphate Fertilizer Production source category?

Today's rule also finalizes, as proposed, revisions to several other Phosphate Fertilizer Production NESHAP and NSPS requirements. We are finalizing, as proposed, changes to clarify applicability and certain definitions, as follows:

- Adopting the proposed conditions in NESHAP subpart BB that exclude the use of evaporative cooling towers for any liquid effluent from any wet scrubbing device installed to control HF emissions from process equipment; and
- Finalizing the proposed revisions changing the word ''cookers'' in NSPS subpart W to ''coolers.''

We are finalizing, as proposed, several changes to testing, monitoring, recordkeeping, and reporting to provide consistency, clarification, and flexibility, as follows:

- Finalizing the proposed revisions to NESHAP subpart BB that require a minimum pressure drop of 5 inches of water column for facilities that use pressure differential in parametric monitoring;

- Finalizing the proposal to remove the requirement in NESHAP subpart BB that facilities must request and obtain approval of the Administrator for changing operating limits;
- Adopting the proposed monitoring requirements for fabric filters in NESHAP subpart BB;
- Adopting the proposed addition of a site-specific monitoring plan and calibration requirements for CMS in NESHAP subpart BB;
- Adopting the proposed term ''absorber'' in lieu of ''scrubber'' in NESHAP subpart BB;
- Adopting the proposed format of NESHAP subpart BB to reference tables for emissions limits and monitoring requirements;
- Adopting the proposed provisions in NSPS subpart V, NSPS subpart W, and NSPS subpart X that require the owner or operator to establish an allowable range for the pressure drop through the process scrubbing system, keep records of the daily average pressure drop through the process scrubbing system, and keep records of deviations;
- Adopting the proposed term ''absorber'' in lieu of ''scrubbing system'' in NSPS subpart V; and
- Adopting the proposed term ''absorber'' in lieu of ''process scrubbing system'' in NSPS subpart W and NSPS subpart X.

We are also finalizing changes to the NESHAP and NSPS for the Phosphate Fertilizer Production source category on issues raised in response to the proposed rulemaking, as follows (refer to section VI.E.2 of this preamble for further details):

- Revising the definitions of ''phosphate fertilizer process line'' and ''phosphate fertilizer production plant'' in NESHAP subpart BB to reference granular phosphate fertilizer;
- Finalizing liquid-to-gas ratio monitoring in NESHAP subpart BB for low-energy absorbers (*i.e.,* absorbers that are designed to operate with pressure drops of 5 inches of water column or less) in lieu of monitoring influent liquid flow and pressure drop through the absorber;
- Clarifying in NESHAP subpart BB that during the most recent performance test, if owners or operators demonstrate compliance with the emission limit while operating their control device outside the previously established operating limit, owners or operators must establish a new operating limit based on that most recent performance test and notify the Administrator that the operating limit changed based on data collected during the most recent performance test; and
- Clarifying in NESHAP subpart BB that facilities not be required to obtain approval, and, instead, immediately comply with a new operating limit when it is developed and submitted to the Administrator.

F. What are the effective and compliance dates of the standards for the Phosphate Fertilizer Production source category?

The revisions to the NSPS and NESHAP standards being promulgated in this action for the Phosphate Fertilizer Production source category are effective on August 19, 2015.

The compliance date in NESHAP subpart BB for when to install, calibrate, and maintain a bag leak detection system on a fabric filter is August 19, 2016. We believe that 1 year is necessary because some facilities that currently operate a fabric filter do not have a bag leak detection system and will need time to purchase and install this compliance monitoring equipment and implement quality assurance measures.

The compliance date in NESHAP subpart BB for the revised startup and shutdown requirements is August 19, 2015. We determined that the feasibility of operating the control devices used to control HAP emissions from phosphate fertilizer production is not limited by specific process operating conditions.

Finally, to ensure continuous compliance with the standard, the compliance date for the monitoring and recordkeeping requirements in NSPS subparts V, W, and X for all new granular DAP plants, TSP plants, and GTSP storage facilities is August 19, 2015, or upon startup, whichever is later.

G. What are the requirements for submission of performance test data to the EPA for the Phosphate Fertilizer Production source category?

As stated in the preamble to the proposed rule, the EPA is taking a step to increase the ease and efficiency of data submittal and data accessibility. Specifically, the EPA is requiring owners and operators of phosphate fertilizer facilities to submit electronic copies of certain required performance test reports.

As mentioned in the preamble of the proposal, data will be collected by direct computer-to-computer electronic transfer using EPA-provided software. As discussed in the proposal, the EPA-provided software is an electronic performance test report tool called the Electronic Reporting Tool (ERT). The ERT will generate an electronic report package which will be submitted to the Compliance and Emissions Data Reporting Interface (CEDRI) and then archived to the EPA's Central Data Exchange (CDX). A description and instructions for use of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/index.html,* and CEDRI can be accessed through the CDX Web site at *www.epa.gov/cdx.*

The requirement to submit performance test data electronically to the EPA does not create any additional performance testing and will apply only to those performance tests conducted using test methods that are supported by the ERT. A listing of the pollutants and test methods supported by the ERT is available at the ERT Web site. The EPA believes, through this approach, industry will save time in the performance test submittal process. Additionally, this rulemaking benefits industry by cutting back on recordkeeping costs as the performance test reports that are submitted to the EPA using CEDRI are no longer required to be kept in hard copy.

As mentioned in the proposed preamble, state, local, and tribal agencies will benefit from more streamlined and accurate review of performance test data that will be available on the EPA WebFIRE database. The public will also benefit. Having these data publicly available enhances transparency and accountability. For a more thorough discussion of electronic reporting of performance tests using direct computer-to-computer electronic transfer and using EPA-provided software, see the discussion in the preamble of the proposal.

In summary, in addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with performance test data will save industry, state, local, and tribal agencies, and the EPA significant time, money, and effort while improving the quality of emission inventories, air quality regulations, and enhancing the public's access to this important information.

V. What is the rationale for our final decisions and amendments for the Phosphoric Acid Manufacturing source category?

For each issue related to the Phosphoric Acid Manufacturing source category, this section provides a description of what we proposed and what we are finalizing for the issue, the EPA's rationale for the final decisions and amendments, and a summary of key comments and responses. For all comments not discussed in this preamble, comment summaries and the EPA's responses can be found in the Comment Summary and Response document available in the docket.

A. Residual Risk Review for the Phosphoric Acid Manufacturing Source Category

1. What did we propose pursuant to CAA section 112(f) for the Phosphoric Acid Manufacturing source category?

Pursuant to CAA section 112(f), we conducted a residual risk review and presented the results of this review, along with our proposed decisions regarding risk acceptability and ample margin of safety, in the November 7, 2014, proposed rule for the Phosphoric Acid Manufacturing NESHAP (79 FR 66512). The results of the risk assessment are presented briefly below in Table 2 of this preamble, and in more detail in the residual risk document, ''Residual Risk Assessment for Phosphate Fertilizer Production and Phosphoric Acid Manufacturing Source Categories in support of the July 2015 Risk and Technology Review Final Rule,'' which is available in the docket for this rulemaking.

TABLE 2—HUMAN HEALTH RISK ASSESSMENT FOR PHOSPHORIC ACID MANUFACTURING

Category & number of facilities modeled	Cancer MIR (in 1 million)		Cancer incidence (cases per year)	Population with risks of 1-in-1 million or more	Population with risks of 10-in-1 million or more	Max chronic non-cancer HI		Worst-case max acute non-cancer HQ
	Based on actual emissions	Based on allowable emissions				Based on actual emissions	Based on allowable emissions	
Phosphoric Acid (12 facilities).	0.09	0.09	0.0002	0	0	0.2	0.3	HQ_{REL} = 2 (hydrofluoric acid) HQ_{AEGL-1} = 0.6 (hydrofluoric acid).
Facility-wide (12 facilities).	0.5	....	0.001	0	0	0.2		

Based on actual emissions for the Phosphoric Acid Manufacturing source category, the maximum individual risk (MIR) was estimated to be less than 1-in-1 million, the maximum chronic non-cancer target organ-specific hazard index (TOSHI) value was estimated to be up to 0.2, and the maximum off-site acute hazard quotient (HQ) value was estimated to be up to 2. The total estimated national cancer incidence from this source category, based on actual emission levels, was 0.0002 excess cancer cases per year, or one case in every 5,000 years. Based on MACT-allowable emissions for the Phosphoric Acid Manufacturing source category, the MIR was estimated to be less than 1-in-1 million, and the maximum chronic non-cancer TOSHI value was estimated to be up to 0.3. We also found there were emissions of several persistent and bio-accumulative HAP (PB–HAP) with an available RTR multipathway screening value, and with the exception of Hg and cadmium compounds, the reported emissions of these HAP (*i.e.,* lead compounds, dioxin/furan compounds, and polycyclic organic matter (POM) compounds), were below the multipathway screening value for each compound. One facility emitted divalent Hg (Hg^{2+}) above the Tier I screening threshold level, exceeding the screening threshold by a factor of 7 and the cadmium emissions exceeded the cadmium screening threshold by a factor of 2. Consequently, we conducted a Tier II screening assessment, in which both pollutants of concern were below the Tier II screening threshold, indicating no potential for multipathway impacts of concern from this facility. The maximum facility-wide MIR was less than or equal to 1-in-1 million and the maximum facility-wide TOSHI was 0.2. We weighed all health risk factors in our risk acceptability determination, and we proposed that the residual risks from the Phosphoric Acid Manufacturing source category are acceptable.

We then considered whether the Phosphoric Acid Manufacturing NESHAP provides an ample margin of safety to protect public health and prevents, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect. In considering whether the standards should be tightened to provide an ample margin of safety to protect public health, we considered the same risk factors that we considered for our acceptability determination and also considered the costs, technological feasibility, and other relevant factors related to emissions control options that might reduce risk associated with emissions from the source category. We proposed that the current standards provided an ample margin of safety to protect public health. With respect to adverse environmental effects, none of the individual modeled concentrations for any facility in the source category exceeded any of the ecological benchmarks (either the lowest-observed-adverse-effect level (LOAEL) or no-observed-adverse-effect level (NOAEL)). Based on the results of our screening analysis for risks to the environment, we also proposed that the current standards prevent an adverse environmental effect.

2. How did the risk review change for the Phosphoric Acid Manufacturing source category?

The residual risk review for the Phosphoric Acid Manufacturing source category did not change since proposal (79 FR 66512). Accordingly, we are not tightening the standards under section 112(f)(2) based on the residual risk review, and are thus readopting the existing standards under section 112(f)(2).

3. What key comments did we receive on the risk review, and what are our responses?

The comments received on the proposed residual risk review were generally supportive of our determination of risk acceptability and ample margin of safety analysis. However, we received several comments requesting we make changes to the residual risk review, including:

- Update the residual risk review with the recommendations and information from the National Academy of Sciences (NAS);
- Incorporate the best currently available information on children's exposure to lead, and go beyond using the 2008 Lead National Ambient Air Quality Standards (NAAQS);
- Reevaluate whether the residual risk review is consistent with the key recommendations made by the Science Advisory Board (SAB);
- Clarify in the rulemaking docket that data received by industry were commensurate with the relevant statutory obligations;
- Revise HF emission data because they are not representative of actual HF emissions, but rather overestimate emissions causing the residual risk review to have an overtly conservative bias;

- Reconsider the assumption used in the NESHAP residual risk assessment that all chromium is hexavalent chromium;
- Revise certain stack parameters used in the analysis;
- Clarify meteorological data used in the analysis;
- Adequately explain rationale for the maximum 1-hour emission rate used for determining potential acute exposures;
- Clarify the selection of ecological assessment endpoints; and
- Provide some quantitative or qualitative rationale for the characterization of the exposure modeling uncertainty.

We evaluated the comments and determined that no changes were needed. Since none of these comments had an effect on the final rule, their summaries and corresponding EPA responses are not included in this preamble. A summary of these comments and our responses can be found in the Comment Summary and Response document available in the docket for this action (EPA–HQ–OAR–2012–0522).

4. What is the rationale for our final approach and final decisions for the risk review?

For the reasons explained in the proposed rule, we determined that the risks from the Phosphoric Acid Manufacturing source category are acceptable, the current standards provide an ample margin of safety to protect public health, and prevent an adverse environmental effect. Since proposal, neither the risk assessment nor our determinations regarding risk acceptability, ample margin of safety or adverse environmental effects have changed. Therefore, pursuant to CAA section 112(f)(2), we are finalizing our residual risk review as proposed.

B. Technology Review for the Phosphoric Acid Manufacturing Source Category

1. What did we propose pursuant to CAA section 112(d)(6) for the Phosphoric Acid Manufacturing source category?

Pursuant to CAA section 112(d)(6), we conducted a technology review, which focused on identifying and evaluating developments in practices, processes, and control technologies for the emission sources in the Phosphoric Acid Manufacturing source category. At proposal, we did not identify cost-effective developments in practices, processes, or control technologies that warrant revisions to the NESHAP for this source category. More information concerning our technology review can be found in the memorandum, ‘‘CAA Section 111(b)(1)(B) and 112(d)(6) Reviews for the Phosphoric Acid Manufacturing and Phosphate Fertilizer Production Source Categories,’’ which is available in the docket, and in the preamble to the proposed rule, 79 FR 66538–66539.

2. How did the technology review change for the Phosphoric Acid Manufacturing source category?

The technology review for the Phosphoric Acid Manufacturing source category did not change since proposal (79 FR 66512). Therefore, we are not revising NESHAP subpart AA based on the technology review.

3. What key comments did we receive on the technology review, and what are our responses?

Commenters agreed with our conclusion that there are no new cost-effective developments in practices, processes, or control technologies that can be applied to the Phosphoric Acid Manufacturing source category that would reduce HAP emissions below current levels.

4. What is the rationale for our final approach for the technology review?

For the reasons explained in the proposed rule, we concluded that additional standards are not necessary pursuant to CAA section 112(d)(6); therefore, we are not finalizing changes to NESHAP subpart AA as part of our technology review.

C. CAA Sections 112(d)(2), 112(d)(3), and 112(h) for the Phosphoric Acid Manufacturing Source Category

1. What did we propose pursuant to CAA sections 112(d)(2), 112(d)(3), and 112(h) for the Phosphoric Acid Manufacturing source category?

We proposed MACT standards for HF and Hg pursuant to CAA sections 112(d)(2) and 112(d)(3), and work practice standards pursuant to CAA section 112(h), for phosphate rock calciners, an emissions source that was initially regulated for HAP metals using PM as a surrogate. We proposed regulating two pollutants, Hg and HF, which were not directly regulated under the initial NESHAP subpart AA. We proposed eliminating the use of PM as a surrogate for Hg and proposed a Hg emission limit for phosphate rock calciners. Because control devices may be necessary to meet the proposed Hg limits for phosphate rock calciners, we proposed monitoring and testing requirements in NESHAP subpart AA for the two types of control systems evaluated as alternatives for control of Hg: Adsorbers (typically fixed bed carbon), and sorbent injection (*i.e.,* activated carbon injection (ACI)) followed by a wet electrostatic precipitator (WESP) or followed by fabric filtration. We also proposed the addition of methods to monitor emissions of Hg using continuous emissions monitoring systems (CEMS). We also proposed a maximum calcination temperature of less than 1,600 degrees Fahrenheit for phosphate rock calciners as a work practice standard to control HF emissions. In addition to proposing a maximum calcination temperature, we proposed to require that emissions from phosphate rock calciners be routed to an absorber to limit emissions of HF from phosphate rock calciners.

Also, we did not propose revised emissions limits for rock dryers because this process is no longer used in the NESHAP regulated source categories for phosphoric acid or phosphate fertilizer (*i.e.,* the rock dryers that were previously used in this industry are no longer in operation).

Finally, we proposed a work practice applicable to facilities when new gypsum dewatering stacks are constructed that would limit the size of active gypsum dewatering stacks and control fugitive HF emissions. When new gypsum dewatering stacks are constructed, we proposed that the ratio of total active gypsum dewatering stacks area (*i.e.,* sum of the footprint acreage of all existing and new active gypsum dewatering stacks combined) to annual phosphoric acid manufacturing capacity must not be greater than 80 acres per 100,000 tons of annual phosphoric acid manufacturing capacity (equivalent P_2O_5 feed). As we stated in the preamble to the proposed rule, limiting the size of gypsum dewatering stacks would minimize emissions by creating an upper bound on emissions. We also proposed work practice standards to control HF emissions from gypsum dewatering stacks and cooling ponds. We proposed a list of control techniques for facilities to use in development of a site-specific gypsum dewatering stack and cooling pond management plan to control fugitive HF emissions. Unless the active gypsum dewatering stack or cooling pond commenced construction or reconstruction after the date of publication of the final rule, we proposed that each facility use at least one of these control techniques. For each active gypsum dewatering stack or cooling pond that commenced construction or reconstruction after the date of publication of the final rule, we proposed that each facility use two of the listed control techniques.

2. How did our final rule change from what we proposed pursuant to CAA sections 112(d)(2), 112(d)(3), and 112(h) for the Phosphoric Acid Manufacturing source category?

In consideration of comments received during the public comment period for the proposed rulemaking, we are finalizing the proposed BTF Hg limit in NESHAP subpart AA for new phosphate rock calciners. We are not finalizing the proposed BTF Hg limit in NESHAP subpart AA for existing phosphate rock calciners. Instead, we are finalizing a MACT floor Hg limit for existing phosphate rock calciners based on the results of the MACT floor calculations for Hg that are discussed in the preamble of the proposed rule (79 FR 66533). We are also revising our estimated costs in the final rule as discussed in section V.C.3.a.i of this preamble. In addition, we are not finalizing work practice standards for HF from phosphate rock calciners, as proposed. Instead, as discussed in section V.C.3.a.ii of this preamble, we are including a total fluoride emission limit for phosphate rock calciners in NESHAP subpart AA.

Also, in consideration of comments received (see section V.C.3.b.i of this preamble for details), we are not adopting the proposed work practice in NESHAP subpart AA that limits the size of active gypsum dewatering stacks (which would have been applicable to facilities when new gypsum dewatering stacks are constructed). Lastly, we are finalizing in NESHAP subpart AA the work practice standard as proposed that requires owners or operators to prepare and operate in accordance with a gypsum dewatering stack and cooling pond management plan. However, based on analysis of public comments, we are making several changes to the specific control techniques that we proposed as options in the plan for controlling fugitive HF emissions (see section V.C.3.b.ii of this preamble for details on these changes).

3. What key comments did we receive on what we proposed pursuant to CAA sections 112(d)(2), 112(d)(3), and 112(h), and what are our responses?

We received several comments regarding the proposed addition of numeric emission limits for Hg and work practice standards for HF emissions from phosphate rock calciners, and the addition of gypsum dewatering stack and cooling pond work practices for the Phosphoric Acid Manufacturing source category. The following is a summary of the significant comments we received regarding these topics and our responses to them. Other comments received and our responses to those comments can be found in the Comment Summary and Response document available in the docket for this action (EPA–HQ–OAR–2012–0522).

a. MACT and Work Practice Standards for Phosphate Rock Calciners—i. Hg Emission Limits for Phosphate Rock Calciners—Comment. Some commenters did not support the EPA's decision to set a BTF limit for Hg from phosphate rock calciners because the emissions do not present unacceptable risks nor do the emission limits yield any benefits. The commenters stated that the EPA fails to show that the proposed BTF Hg limit would produce health or environmental benefits that justify the costs of achieving the standard as they assert is required by CAA section 112(d)(2). Commenters further claimed that the EPA's own risk assessment shows that the BTF limit is not necessary from a risk standpoint because the NESHAP regulation, prior to implementation of the proposed Hg BTF limits, provides an ample margin of safety to protect public health and prevents, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect. The commenters maintained that under CAA section 112(d)(2), the EPA may set an emission limit that is more stringent than the MACT floor only if the Agency determines that the BTF limit is ''achievable'' based on a consideration of the relative costs and benefits. One commenter cited regulations where the EPA did not set BTF limits for a particular pollutant because the benefits were minimal and the risk would not be appreciably reduced. Commenters supported setting the MACT floor as the Hg limit.

Commenters stated the Hg control devices that the EPA evaluated for the phosphate rock calciner BTF limit were not technically feasible, but did note two potential solutions. Specifically, the commenters stated that use of ACI just prior to the existing WESP or after the WESP with a fabric filter is not technically feasible. The commenters explained the exhaust gas downstream of the WESP is completely saturated and contains entrained water droplets; this would plug the fabric filter, result in performance degradation of the activated carbon, and could lead to plugging of the injection lances and formation of deposits on the ducts. The commenters further explained that it would not be feasible to install heating systems or design engineering control to avoid these problems, due to high costs and the technical complexity. The commenters noted that installing the ACI just prior to the WESP was also not feasible, again due to performance degradation of the activated carbon, but also due to the fact that the existing WESPs could not capture the additional particulate load. The commenters reported that installing the ACI upstream of the existing venturi scrubber is technically feasible, because the gas upstream of the scrubber is not completely saturated. However, the commenters noted several design and operational modifications that would be necessary; these modifications focused on reducing the temperature of the exhaust gas streams to less than 375 degrees Fahrenheit. When installing ACI upstream of the existing venturi scrubber, the ACI vendor used by the commenter recommended the use of treated (*e.g.,* halogenated) carbon at an injection rate of 30 lb/MMacf, in order to meet the BTF Hg limit. The commenter said that the carbon injection rate may need to be as much as 30 lb/MMacf based on site-specific conditions, such as temperature, Hg concentration, moisture, and sulfur content of the phosphate rock calciner exhaust stream. In support of a high injection rate, the commenter also cited a reference from 1994 that observed an increased injection rate was necessary due to temperature of the exhaust gas stream.

Regarding fixed-bed carbon adsorption, commenters stated a traditional fixed-bed carbon adsorption system would not be feasible due to the presence of entrained water droplets that would severely degrade sorbent performance and cause plugging within the bed. The commenters indicated that new Gore Mercury Control System (GMCS) technology might be technically feasible because it uses a fixed sorbent structure with a sorbent polymer composite material to adsorb Hg; the GMCS polymer composite material might protect the sorbent from entrained water droplets and other contaminants in the flue gas. The commenters stated that to use a GMCS fixed-bed carbon adsorption system, several adjustments to the calciners would be necessary, as well as a pilot study to confirm the feasibility. Another commenter also reported they were evaluating the use of the GMCS system, but were only in preliminary stages as their phosphate rock calciner is not yet operating. A commenter also explained that each phosphate rock calciner would need its own controls and a single control system for all phosphate rock calciners would not be feasible due to safety and operational concerns.

Several commenters argued that ACI and fixed-bed carbon adsorption were not cost effective for controlling Hg emissions from phosphate rock calciners. Two commenters reported a site-specific cost estimate for installing GMCS fixed-bed carbon adsorption downstream of the existing WESP, with capital costs of $32 million and annual costs of $5.8 million; the resulting cost-effectiveness was approximately $40,000 per pound of Hg. The commenters noted the GMCS cost-effectiveness ($40,000/lb Hg) was much higher than the cost-effectiveness the EPA presented in the proposed rule ($8,000/lb Hg) for a traditional fixed-bed carbon adsorption system. Commenters also reported a site-specific cost estimate for installing ACI upstream of the existing venturi scrubbers, with capital costs of $21.1 million and annual costs of $9.1 million; this resulted in a cost-effectiveness of approximately $63,000 per pound of Hg. The commenters noted this ACI cost-effectiveness ($63,000/lb Hg) was much higher than the cost-effectiveness the EPA presented in the proposed rule ($12,100/lb Hg) for ACI. The commenters stated that because their costs for ACI and GMCS fixed-bed carbon adsorption were site-specific, they are much more representative than the costs developed by the EPA for the proposed rule. Finally, one commenter stressed that the site-specific Hg control cost-effectiveness numbers were well above the cost-effectiveness for other rules where the EPA implemented BTF Hg controls. Another commenter noted that preliminary information for installing Hg controls resulted in estimates of $17.5 million in capital costs and $10 million for annual costs.

Response. Based on these comments, the Agency revised the BTF costs analysis and determined that setting a BTF Hg emission limit for existing phosphate rock calciners would impose a significant economic impact to PotashCorp (PCS) Aurora, the only facility that we are aware of with phosphate rock calciners; therefore, we are not finalizing the BTF Hg limit for existing phosphate rock calciners. The annualized control costs for this company would be approximately 0.9 percent to 5.3 percent of revenues (see ''PCS Phosphate Response to USEPA Request for Aurora Plant Financial Information, May 8, 2015,'' which is available in the docket for this rulemaking). While these costs are small for the industry, they may be significant for the company and particularly significant for the facility. For the company, there may be a negative impact on profitability. If the company is unable to pass on the increase in the cost of manufacturing the product by raising prices, the facility will either face a potentially significant reduction in profitability or have to close a process or facility. Therefore, the Agency is finalizing a MACT floor Hg limit of 0.14 milligrams (mg) Hg per dry standard cubic meter (dscm) at 3-percent O_2 for existing phosphate rock calciners and does not anticipate that any facilities will need to install a new control device to meet the existing phosphate rock calciner Hg limit. Also, we are finalizing the proposed BTF Hg limit (*i.e.,* 0.014 mg Hg/dscm at 3-percent O_2) for new phosphate rock calciners, as facilities should be better able to plan for the costs of controls for new sources. The following discussion provides the details of these decisions.

The results of the residual risk analyses are not part of the BTF MACT determination, and, accordingly, the commenters' concern about not considering risk results is not appropriate. See *Sierra Club* v. *EPA,* 353 F.3d 976, 981 (D.C. Cir. 2004). Analyzing the risk would not be a practical requirement, as, typically, MACT standards are set in advance of a residual risk or technology review of the standard. Additionally, the statutory language excerpt cited by the commenter does not accurately reflect the CAA language, which requires the Agency to consider costs associated with the emission reductions, but does not require a demonstration of benefits. The Agency appropriately met its requirements under CAA section 112(c) and (d) by first evaluating a MACT floor level of control for Hg emissions from phosphate rock calciner units and then evaluating cost-effective controls for further reducing emissions BTF level.

The Agency appreciates the commenters' site-specific review of Hg control device technologies and agrees with the commenters' revisions to certain aspects of the technical feasibility of ACI and fixed-bed carbon adsorption. At proposal, we noted that high moisture streams may result in plugging of the fabric filter, as it relates to ACI use. However, we did not consider that entrained water droplets in the high moisture streams would degrade carbon sorbent performance for both ACI and fixed-bed carbon adsorption, or lead to plugging within a fixed-bed. As a result of the additional information provided by the commenters, we agree that it is not technically feasible to use ACI just prior to the existing WESP or after the WESP with a fabric filter to control Hg emissions from phosphate rock calciners, based on current operations. Based on information available at this time, we also agree that a traditional fixed-bed carbon adsorption system is not technically feasible to control Hg emissions from phosphate rock calciners.

The commenters also stated, and the EPA agrees, that use of ACI (specifically halogenated carbon) is technically feasible to control Hg emissions from phosphate rock calciners if ACI is installed upstream of the existing venturi scrubber, where the moisture content is lower. However, we disagree with the commenters' assessment that a carbon injection rate of 30 lb/MMacf would be necessary to achieve a 90 percent reduction in Hg emissions from phosphate rock calciners. The commenters' carbon injection rate estimate is much higher than ACI installations at coal power plants and cement kilns, and while phosphate rock calciners may have unique exhaust gas properties, these properties do not warrant such an extreme carbon feed rate.

To provide additional context on carbon injection rates, we reviewed numerous ACI Hg reduction studies conducted through a National Energy Technology Laboratory (NETL) research program under the Department of Energy (DOE), as well as other studies, which are available in Docket ID No. EPA–HQ–OAR–2012–0522. In our review, we considered the impact on carbon injection rates due to temperature, moisture content, Hg concentration, sulfur content (*i.e.,* sulfur trioxide (SO_3) concentration), and carbon sorbent type. Considering the information in these studies, we found it common for carbon injection rates of 5 lb/MMacf or less to result in 90 percent Hg removal, although higher injection rates are warranted in some instances. We also found that at certain facilities, high injection rates do not result in 90 percent Hg removal; however, in several of these cases those data are for standard powdered activated carbon (PAC), *i.e.,* activated carbon that has not been treated with halogens, or exhaust gases containing high SO_3 concentrations. Specifically, we identified a 2008 document[3] that combines results from several studies demonstrating the relationship between PAC injection rate (lb/MMacf) and percent Hg removal. While Figure 2 in this 2008 document shows injection rates up to 20 lb/MMacf using standard

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[3] Refer to Figures 2 and 3 of ''DOE NETL Hg Field Testing Update_2008'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522.

PAC (*e.g.,* not halogenated carbon), data for halogenated PAC, in Figure 3 of the 2008 document, shows a maximum of approximately 9 lb/MMacf in order to achieve 90 percent Hg removal from the gas stream. It accords with our general knowledge that standard PAC can have a high control efficiency if halogens are present in the flue gas to oxidize elemental Hg so that it can be adsorbed on the particles injected and subsequently captured in the particle control device. Thus, if halogens are not present in sufficient quantities to oxidize the elemental Hg present, the unoxidized Hg present will continue to be emitted, since it would not be adsorbed on the particles and captured in the particle control device. This situation can be remedied through the use of halogenated PAC, which will oxidize the elemental Hg present so that it can be adsorbed on the particles and later captured. Thus, while we agree with the vendor's recommendation that halogenated PAC is most likely to result in better Hg removal efficiencies for the phosphate rock calciners, we disagree with the relevance of the commenter's cited 1994 document. The ACI vendor used by the commenter recommended treated (*e.g.,* halogenated) PAC as the most likely sorbent type for phosphate rock calciner Hg treatment and the cited 1994 document evaluated standard PAC. In addition, as noted above, there have been more recent studies and significant progress in PAC design since 1994, and as such we do not believe the PAC evaluated in the 1994 document would result in the Hg reductions that today's PAC can achieve. Therefore, we determined that PAC type is a critical factor for Hg removal efficiencies for this source category.

The commenter also noted that modifications focused on reducing the temperature of the exhaust gas streams would be necessary in order for ACI to be effective when installed prior to the existing venturi scrubber. This reduced operating temperature for the phosphate rock calciner exhaust would be in a similar range as coal utility boilers; it is common for coal utility boilers to have exhaust gases at temperatures exceeding 300 degrees Fahrenheit (see the documents ''Coal Plant Hg Controls Update_EPA_2005'' and ''DOE NETL Hg Field Testing Update_2008,'' which are available in Docket ID No. EPA–HQ–OAR–2012–0522). Therefore, the cited coal utility boiler studies are appropriate and show that ACI is effective in the new temperature range. This further refutes the commenter's citation of the 1994 document regarding temperature concerns and the necessity of an injection rate as high as 30 lb/MMacf.

Data are available demonstrating that increased SO_3 levels are detrimental to sorbent performance. We found that higher carbon injection rates are typical for plants with higher SO_3 concentration in the exhaust stream; for coal utility boilers, this can occur when the fuel is high-sulfur bituminous coal. The concentration of SO_3 in emissions from coal utility boilers is also increased by certain control devices (*e.g.,* selective catalytic reduction) that do not exist at the phosphate rock calciners. For information on SO_3 impacts, see the documents ''DOE NETL Hg Field Testing Update_2008'' and ''ADA ACI Overview_2010,'' which are available in Docket ID No. EPA–HQ–OAR–2012–0522. Of note, certain PAC sorbents are designed to work in high-sulfur environments (see the document ''Calgon Fluepac ST brochure,'' available in Docket ID No. EPA–HQ–OAR–2012–0522). Based on this available information, we do not believe SO_3 concentration in the phosphate rock calciner exhaust gas stream will severely impact ACI performance to a level requiring a carbon injection rate of 30 lb/MMacf.

Additionally, we identified a pilot study that was conducted in 2007 on a cement kiln at the Ash Grove Durkee facility that resulted in more than 90 percent Hg removal efficiencies using carbon injection rates of only 3 lb/MMacf. Of note, the Hg concentration in the cement kiln exhaust gas was more than 10 times higher than the Hg concentration in the phosphate rock calciner exhaust gas. This study is presented in the document ''Carbon Injection Pilot Test Durkee OR_2007,'' available in Docket ID No. EPA–HQ–OAR–2012–0522.

While we acknowledge that phosphate rock calciner exhaust streams may have certain unique characteristics, we do not agree with a PAC injection rate of 30 lb/MMacf based on the data available, as discussed above. We believe a halogenated PAC injection rate of 10 lb/MMacf or lower (for ACI installed upstream of the existing venturi scrubbers) is sufficient for meeting the BTF Hg limit for phosphate rock calciners.

Commenters also noted, and the EPA agrees, that GMCS technology would be technically feasible to control Hg emissions from phosphate rock calciners. We also agree that individual GMCS fixed-bed carbon adsorption systems would be necessary for each of the six phosphate rock calciners. The commenters noted that two full-scale operations are actively using GMCS fixed-bed carbon adsorption systems to control Hg. Furthermore, based on additional discussion with industry (see ''EPA Meeting Minutes for PCS Aurora Hg Discussion, March 12, 2015,'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522), we now know that three full-scale operations use GMCS to control Hg, with two additional operations to come online soon. These full-scale operations are located at coal power plants, not phosphoric acid manufacturing processes. Based on the vendor-provided information and the fact that GMCS technology is currently used at coal power plants to comply with Hg emission limits, we believe GMCS technology is technically feasible. In regards to the need for a pilot study, facilities would have time to design, construct, and test the system.

Although we have determined that two control technologies are technically feasible to control Hg emissions from phosphate rock calciners, we evaluated costs for the BTF Hg limit based on the estimated lower cost technology, installation of halogenated ACI upstream of the existing venturi scrubber. We used the ACI cost data provided by the commenter to estimate the costs for complying with the BTF Hg limit. However, instead of basing the annual carbon cost on an injection rate of 30 lb/MMacf, we applied injection rates of 5 and 10 lb/MMacf of halogenated carbon for reasons stated above. As provided by the commenter, the capital cost for installing six ACI units on each existing phosphate rock calciner is approximately $21,150,000. The annual cost ranges from approximately $4,320,000 (when a carbon injection rate of 5 lb/MMacf is used) to approximately $5,280,000 (when a carbon injection rate of 10 lb/MMacf is used); this results in Hg reductions of 145 pounds of Hg per year. As previously stated, these annual costs imposed a significant economic burden and we are not finalizing the BTF Hg limit for existing phosphate rock calciners.

Existing phosphate rock calciners must comply with a Hg emission limit that equals the MACT floor at 0.14 mg Hg/dscm at 3-percent O_2. The MACT floor was calculated using the upper prediction limit (UPL) methodology, which was discussed in the preamble of the proposed rule (see 79 FR 66533) and is also discussed in the memorandums ''Maximum Achievable Control Technology (MACT) Floor Analysis for Phosphate Rock Calciners at Phosphoric Acid Manufacturing Plants—Final Rule'' and ''Use of the Upper Prediction Limit for Calculating MACT Floors,'' which are available in the docket for this action. Based on the available data, the existing phosphate rock calciners would be able to comply with this limit without installing additional Hg controls.

We evaluated application of the BTF Hg limit for new phosphate rock calciners. Facilities would have time to plan for and consider the costs when determining whether to construct a new phosphate rock calciner. Additionally, sources may choose to only add one new calciner unit at a time, which would have considerably less impact than the costs associated with retrofitting all units at an existing site. Therefore, we evaluated the cost-effectiveness for installing Hg controls on a new phosphate rock calciner. Using the same cost data provided by the commenter, installing a single ACI would have capital costs of approximately $3,500,000. The annual cost ranges from approximately $720,000 (when a carbon injection rate of 5 lb/MMacf is used) to approximately $880,000 (when a carbon injection rate of 10 lb/MMacf is used). This results in Hg reductions of 24 pounds of Hg per year for a single calciner unit, assuming the new phosphate rock calciner has similar emissions as the existing phosphate rock calciners at PCS Aurora. The resulting cost-effectiveness is estimated to be $29,800 to $36,400 per pound of Hg reduced, which we consider cost effective for new sources. This facility-level cost-effectiveness for Hg for new sources is comparable to values the EPA found to be cost effective for removal of Hg at the facility-level in other air toxics rules.[4] Consequently, new phosphate-rock calciners must comply with the BTF Hg emission limit of 0.014 mg Hg/dscm at 3-percent O_2.

ii. HF Work Practices for Phosphate Rock Calciners—Comment. We received comment regarding HF work practices for phosphate rock calciners. One commenter supported the HF work practices and stated they are consistent with their current phosphate rock calciner operations. Another commenter does not support the implementation of HF work practices for phosphate rock calciners. This commenter, which is considering installation of a calciner in the future, noted that preliminary results indicate a calcination temperature of at least 2,000 degrees Fahrenheit is necessary for their phosphate rock calciner. This commenter also explained they are evaluating a flash calciner, which operates with a much shorter retention time than the fluidized bed calciners currently in operation. The commenter argued that wet scrubbers should not be a requirement of the HF work practice because their phosphate rock calciner will be located in a remote area where treatment and disposal options for scrubber liquors may not be feasible. The commenter recommended the EPA allow for other control technologies with equivalent efficiencies.

Another commenter does not support the use of work practices for HF, and declared the EPA should set numeric emission limits for HF from phosphate rock calciners. The commenter maintained that the EPA failed to satisfy the CAA section 112(h) test it must meet to promulgate work practice standards ''in lieu of'' numerical emission standards. The commenter stated that not using the available emissions data to set a floor limit is unlawful and arbitrary, even if the data are below the detection limit.

Response. We are not adopting the proposed HF work practice standard for phosphate rock calciners in NESHAP subpart AA. Instead, we are adopting an emission limit for total fluoride from phosphate rock calciners. In proposing the HF work practices, we concluded that it was not feasible to prescribe or enforce an emission limit for HF due to limitations in the available EPA Method 320 HF test results (*i.e.,* most of the emissions data were below the method detection limit). We now have concluded, based on analysis of public comments, that it is not feasible to accurately measure HF emissions from phosphoric acid manufacturing processes using EPA Method 320 (see section V.F.3.c of this preamble for further details). However, data are available to establish an emission limit for total fluoride from phosphate rock calciners. In 2015 only one facility operates phosphate rock calciners, which are controlled by a venturi-type scrubber. In response to the April 2010 CAA section 114 request, the facility provided EPA Method 13B total fluoride emission testing results for one of their six identical phosphate rock calciners. We conclude that the total fluoride emission rate achieved by this phosphate rock calciner characterizes the emissions from all six calciners and thus this emission rate was used to determine the MACT floor for total F emissions. Therefore, for phosphate rock calciners, we are setting total F emission limits. We are also setting a work practice standard for periods of startup and shutdown in lieu of this numeric emission limit (see section V.E.3 of this preamble for further details). The use of total fluoride as a surrogate for the HAP HF is consistent with WPPA, SPA, and DAP/MAP process lines, which also have total fluoride emission limits in lieu of HF emission limits.

For the Phosphoric Acid Manufacturing source category, we have a limited dataset for the pollutant total fluoride from phosphate rock calciners. Therefore, we evaluated this specific dataset to determine whether it is appropriate to make any modifications to the UPL approach used to calculate the MACT floor. For the phosphate rock calciner dataset, we performed the following steps: We selected the data distribution that best represents the dataset; ensured that the correct equation for the distribution was then applied to the data; and compared individual components of the limited dataset to determine if the total fluoride standard based on the limited dataset reasonably represents the performance of the units included in the dataset. The results of this analysis are presented below.

The MACT floor dataset for total fluoride from new and existing phosphate rock calciners includes 3 test runs from 1 phosphate rock calciner. After determining that the dataset is best represented by a normal distribution and ensuring that we used the correct equation for the distribution, we considered the selection of a lower confidence level for determining the emission limit by evaluating whether the calculated limit reasonably represents the performance of the unit upon which it is based. In this case, the calculated emission limit is about twice the short-term average emissions from the best performing source, indicating that the emission limit is not unreasonable compared to the actual performance of the unit upon which the limit is based and is within the range that we see when we evaluate larger datasets using our MACT floor calculation procedures. Therefore, we determined that no changes to our standard UPL floor calculation procedure are warranted for this pollutant and subcategory. We are applying the same method of calculating a total fluoride limit as we did for the Hg MACT floor calculation, for which we gave notice in the preamble to the proposed rule. Additional details and background on the MACT floor calculation are provided in the memorandums, ''Maximum Achievable

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[4] National Emission Standards for Hazardous Air Pollutants: Mercury Emissions from Mercury Cell Chlor-Alkali Plants (76 FR 13852); National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (76 FR 24976 and 77 FR 9304); and National Emission Standards for Hazardous Air Pollutants: Gold Mine Ore Processing and Production Area Source Category (75 FR 22470).

Control Technology (MACT) Floor Analysis for Phosphate Rock Calciners at Phosphoric Acid Manufacturing Plants—Final Rule,'' ''Approach for Applying the Upper Prediction Limit to Limited Datasets,'' and ''Use of the Upper Prediction Limit for Calculating MACT Floors,'' which are available in the docket for this action. We also evaluated BTF options for total F, but were unable to identify any cost-effective BTF technologies. Table 3 of this preamble provides the results of the new and existing phosphate rock calciner MACT floor calculations (considering variability) for total F.

TABLE 3—RESULTS OF THE NEW AND EXISTING MACT FLOOR CALCULATIONS FOR TOTAL FLUORIDE FROM PHOSPHATE ROCK CALCINERS AT PHOSPHORIC ACID MANUFACTURING FACILITIES

Pollutant	Results	Units
Total fluoride (for new and existing sources)	9.0E–04	lb/ton of rock feed.

b. Gypsum Dewatering Stack and Cooling Pond Work Practices—i. Ratio of Gypsum Dewatering Stack Area to Phosphoric Acid Manufacturing Capacity—Comment. Several commenters requested that the EPA either reconsider, withdraw, or eliminate the proposed gypsum dewatering stack area limitation of 80 acres per 100,000 tpy capacity (in equivalent P_2O_5 feed). Commenters claimed the use of flawed data and assumptions in the EPA's analysis in the following areas: (1) Ambiguous definitions of a ''gypsum dewatering stack,'' and ''new'' and ''existing'' stacks; (2) inaccurate or outdated data on acreage of existing stacks and production capacity, stack closures, and plans for new stacks; (3) flawed or missing rationale and correlation between the gypsum dewatering stack area and phosphoric acid manufacturing capacity; (4) no technical or legal basis for the selection of the 80-acre cutoff; (5) no consideration given to site-specific variables that influence the acreage of gypsum dewatering stacks; and (6) failure to consider impacts from closing an existing stack prior to commissioning a new stack.

These commenters claimed the term ''gypsum dewatering stack'' is so broadly and ambiguously defined they are unable to determine the scope and impact of the proposed area limitation of 80 acres per 100,000 tpy capacity, or how the proposed limitation would be applied to facilities. They claimed the EPA's definition includes a wide array of features that have never before been considered part of the gypsum dewatering stack (*e.g.,* pumps, piping, all collection and conveyance systems associated with gypsum to the stack and process wastewater return to the plant). Commenters argued that the EPA underestimated stack acreage used in the analysis and that the estimates should be much larger when the ''total system'' acreage is used. These commenters stated that using the ''total system'' acreage in the analysis demonstrates that the EPA significantly underestimated the number of acres at each facility that would need to be closed. One of these commenters asked whether a vertical expansion of an existing stack would be considered a ''new'' facility, and how the proposed work practice might be evaluated for compliance when surfaces of a ''closed'' facility might be overlapped by an immediately-adjacent ''new'' facility.

Additionally, commenters argued that the EPA's technical rationale for limiting stack area was based on an arbitrary correlation with production capacity. One of these commenters said there is no relationship between gypsum dewatering stack area and phosphoric acid manufacturing capacity, and that outliers were removed from the analysis further confirming no quantitative relationship between stack area and facility capacity. This commenter also asserted that limiting the size of the gypsum dewatering stacks is not proven to limit HF emissions.

Furthermore, two commenters claimed the 80-acre limit does not consider an evaluation of water balance and process water cooling needs for individual facilities. These commenters pointed out that a flat area does not require as large of a footprint for its gypsum dewatering stacks as compared to an area with large topographic relief. One of these commenters provided examples of two gypsum dewatering stacks located in mountainous areas that require larger footprints to construct ponds due to longer runs of pipe, roads, and dike.

Finally, one commenter claimed that an updated acreage-based analysis would need to account for the transition period between a stack becoming ''inactive'' and the point in time of ''closure'' so as not to exceed the acreage limit while constructing a new stack. Another commenter stated that the startup of a gypsum dewatering stack is a lengthy process that may take more than a year, and that the ''ratio'' requirement inaccurately assumes simultaneous closure of an old stack with the opening (*i.e.,* new construction) of a new stack. Another commenter also contended that construction and closure take years to complete and occur simultaneously, and that closing a gypsum dewatering stack before beginning construction on a new stack would require an entire companion production facility to be idled for an extended period and impose ''enormous direct and lost opportunity costs . . . such costs and plant idling are not justified.''

Response. We agree with commenters that the proposed definition of ''gypsum dewatering stack'' is too broad. As we stated in the preamble to the proposed rule, we intended the proposed ratio limit to apply to only the ''footprint acreage'' of the gypsum dewatering stacks, which was deliberately meant to exclude the areas where many supplementary processes (such as pumps, piping, ditches, drainage conveyances, water control structures, collection pools, cooling ponds, surge ponds, auxiliary holding ponds, and any other collection or conveyance system) are located. Therefore, we did not underestimate stack acreage used in the gypsum dewatering stack area limitation analysis, nor did we underestimate the number of acres at each facility that would need to be closed. However, in an effort to clarify the specific emission source that we are regulating in the final rule (NESHAP subpart AA), we have included a new term, ''gypsum dewatering stack system,'' and revised the definition of ''gypsum dewatering stack'' in the final rule. We are finalizing ''gypsum dewatering stack system'' to mean ''the gypsum dewatering stack, together with all pumps, piping, ditches, drainage conveyances, water control structures, collection pools, cooling ponds, surge ponds, auxiliary holding ponds, regional holding ponds and any other collection or conveyance system associated with the transport of gypsum from the plant to the gypsum dewatering stack, its management at the gypsum dewatering stack, and the process wastewater return to the phosphoric acid production or other process.'' We are finalizing ''gypsum dewatering stack'' to mean ''any defined geographic area associated with a phosphoric acid manufacturing plant in which gypsum is disposed of or stored, other than within a fully enclosed building, container, or tank.'' This revised definition of ''gypsum dewatering stack'' is based on Florida Administrative Rule 62–273.200 which regulates phosphogypsum management, and clearly includes any gypsum disposal pile, as well as the associated gypsum pond (which is also known as a settling pond, used to deposit the gypsum slurry, and is often located in the middle of the gypsum disposal pile), but does not include separate cooling ponds (for which we have retained the proposed definition of ''cooling pond'' in the NESHAP subpart AA final rule).

Nevertheless, in light of other concerns raised by commenters, we are not adopting the proposed work practice that limits the size of active gypsum dewatering stacks, which would have been applicable to facilities when new gypsum dewatering stacks are constructed.

As we stated in the preamble to the proposed rule, we did not detect a correlation between gypsum stack dewatering area and phosphoric acid manufacturing capacity; however, we proposed the size limit because we believe that reducing the gypsum dewatering stack area is directly related to reducing HF emissions. We also believed that phosphoric acid manufacturing capacity was related to the size of gypsum dewatering stacks and that it was operationally appropriate to allow large facilities to build larger gypsum dewatering stacks, while limiting smaller facilities to building a proportionally smaller gypsum dewatering stack. However, we have now concluded, based on analysis of public comments and other supplemental information provided, that it is not feasible to require facilities to close gypsum dewatering stacks based on a ratio of total active gypsum dewatering stack area (*i.e.,* sum of the footprint acreage of all active gypsum dewatering stacks combined) to annual phosphoric acid manufacturing capacity. As commenters stated, the gypsum dewatering stack acreage does not relate to production capacity and, importantly, gypsum dewatering stack development must be considered in light of the operations of the entire facility. Factors that affect the size and development of gypsum dewatering stacks include: (1) The availability and topography of land near the facility; (2) facilities generate a substantial amount of gypsum waste in the phosphoric acid manufacturing process; (3) managing the gypsum waste that is generated is an important operating principle for all facilities (regardless of phosphoric acid production capacity); and (4) limiting the gypsum dewatering stack acreage or changing the way facilities build gypsum dewatering stacks could have a detrimental impact on a facility's operations. Additionally, we agree with commenters that closure of a gypsum dewatering stack does not happen immediately, but rather requires a transitional period that can take years to complete. During this transitional period, a new stack is begun, but it may be years before it is fully operational and can receive all gypsum and slurry from the facility. This transitional period would make it difficult, if not impossible, for a facility to comply with the proposed work practice that limits the size of active gypsum dewatering stacks because the proposed size limit assumed immediate closure. Since closure does not happen immediately, and there is no correlation between dewatering stack acreage and phosphoric acid production, we are not adopting the proposed work practice that limits the size of active gypsum dewatering stacks.

We are removing the definition of ''closed gypsum dewatering stack,'' and revising the definition of ''active gypsum dewatering stack,'' as well as the definitions for when a gypsum dewatering stack is considered ''new'' or ''existing'' (see sections V.C.3.b.ii and V.C.3.b.iii of this preamble for further details).

ii. Necessity or Justification of Work Practice Standards for Fugitive HF Emissions—Comment. Numerous commenters claimed that there is insufficient technical analysis as to the feasibility and effectiveness of the control techniques that were proposed as options (as part of a work practice standard in the form of a management plan) for controlling fugitive HF emissions from gypsum dewatering stacks and cooling ponds. One of these commenters supported the EPA's claim that emissions from gypsum dewatering stacks and cooling ponds would inherently constitute fugitive emissions, and that conceptually, a work practice standard is a reasonable approach to emissions control; however, they challenged the technical basis for the specific control techniques listed in the proposed management plan. Commenters contended that the proposed control techniques have not been demonstrated to have an effect on fugitive HF emissions, and stated the EPA did not quantify the expected reductions in HF emissions resulting from the proposed work practice standard for gypsum dewatering stacks and cooling ponds. A commenter noted that some of the control techniques were derived from their facility's title V permit and that the EPA needed to recognize that (a) it is not clear (with a couple of exceptions) that these control techniques provide any significant emission reductions; (b) recent information may not support these control techniques providing emission reductions; and (c) there is considerable uncertainty in the emissions associated with cooling ponds and gypsum dewatering stacks. Another commenter argued that the EPA must justify the control techniques and show that they are not only technically effective, but also cost-effective and achievable within the industry. Commenters asserted that only two sources of information were used by the EPA in its determination of the control techniques that were proposed as options for controlling fugitive HF emissions in the proposed gypsum dewatering stack and cooling pond management plan. Commenters also noted that there is a large amount of uncertainty related to which specific control techniques are feasible and effective in reducing fugitive HF emissions. The following paragraphs provide a summary of the comments that the Agency received on each specific control technique.

Three commenters opposed the use of submerged discharge pipes and siphon breaks below the surface of the cooling pond as a fugitive HF emissions control technique. They claimed that submerging cooling pond discharge lines for above-grade ponds would create a significant risk for a siphon effect to occur when a pumping system is shutdown, causing backpressure on the pump seals back down the line, and, thus, defeating the purpose of the siphon break. One of these commenters added that submerging siphon breaks will impede the ability of these devices to prevent backflow because submersion may interfere with the atmospheric connection needed to make siphon breaks operate properly.

One commenter stated that although they use a rim ditch (cell) building technique, it is not an appropriate work practice for reducing HF emissions, and mentioned that the EPA does not provide data or an explanation of the linkage between minimizing the gypsum dewatering stack surface area and reducing emissions. This commenter suggested that the EPA define the technique as ''a gypsum stack building technique where gypsum slurry is deposited along the stack perimeter with flow directed along a ditch before the liquid flow is conveyed to the settling compartments.'' Another commenter stated that minimizing the gypsum pond surface areas is not feasible in Florida, North Carolina, and Louisiana because gypsum pond surface areas are optimized to provide annual evaporative water losses necessary to maintain zero water discharge.

Several commenters also objected to the wetting of the active gypsum dewatering stack as a fugitive HF emissions control technique because the technique may be infeasible and counter-productive due to water balance issues at nearly every affected facility. One commenter argued that applying fresh water is not feasible (*i.e.,* water trucks are not feasible or safe; irrigation in the West is not feasible; pipes are at risk of freezing) and another commenter stated that using recycled water may actually increase fugitive emissions because HF resides primarily in residual and make-up waters used to transport the gypsum slurry to the gypsum dewatering stack. One commenter contended that determining hot or dry periods is too subjective; therefore, it would be difficult to know when the control technique would apply. Another commenter illustrated the uncertainty of wetting of the active gypsum dewatering stack as a fugitive HF emissions control technique by identifying two studies with contradicting conclusions (one concluded that most HF is emitted from aqueous surfaces and trends with solar radiation, and the other study concluded that drying gypsum is a major source of ambient fluoride emissions from gypsum storage areas).

One commenter challenged the EPA's lack of evidence on the effectiveness of applying slaked lime to gypsum dewatering stacks as a fugitive HF emissions control technique, and claimed that it would not be feasible, referring to rain as threat to eliminate the potential for effectiveness. On the contrary, another commenter described how they apply a lime solution on top of reachable drying gypsum stack areas, and that the reaction of fluoride with slaked lime does result in the ''tie-up'' of volatile F, although they are not aware of any studies that have measured or quantified reductions.

In addition, commenters also claimed that enormous costs would be associated with the fugitive HF emissions control technique requiring facilities to apply soil caps and vegetation to all side slopes of the active gypsum dewatering stack up to 50 feet below the stack top. Some of these commenters mentioned that there are state rules that require soil caps and side vegetation on side slopes for erosion/water impact control, but not for the purpose of fugitive HF emissions control.

Furthermore, commenters requested that the closure of a gypsum dewatering stack not be considered a fugitive HF emissions control technique. One commenter contended that the EPA should allow the final cover on a closed stack to consist of a synthetic liner, as this would achieve the same purpose as a vegetative liner and may be more appropriate in some instances. Another commenter explained that some states and the EPA have closure requirements under Resource Conservation and Recovery Act (RCRA), including, for example, requirements for long term care practices (beyond 20–50 years); shaping and configuration of gypsum dewatering stacks; site security. They suggested that due to these detailed requirements, it would be best to defer to stack closure requirements within other regulations and not have NESHAP requirements that involve or require stack closure.

Finally, commenters requested that if the EPA proceeds with a final rule that includes work practices for reducing fugitive HF emissions from gypsum dewatering stacks or cooling ponds, the work practices should include a flexibility mechanism for facilities to use additional practices not codified during this rulemaking. One commenter asserted that work practice standards that might commonly be practicable for other industries are not universally practicable (or legally permissible) throughout the phosphoric acid and phosphate fertilizer industries, and some practices might be appropriate for some facilities, but not others (depending on location, climate, etc.).

Response. We are adopting the proposed work practice standard that requires owners or operators to prepare, and operate in accordance with a gypsum dewatering stack and cooling pond management plan; however, based on analysis of public comments, we are making some changes to the specific control measures that we proposed as options in the plan for controlling fugitive HF emissions. In the final rule, the Agency is using the terminology ''control measures'' in lieu of the proposed terminology ''control techniques'' because it more accurately describes the list of options in the rule and avoids confusion with other CAA programs. We are finalizing standards that will reduce HAP emissions from gypsum dewatering stacks and cooling ponds because, as explained in the preamble to the proposed rule, the 1999 Phosphoric Acid Manufacturing NESHAP (*i.e.,* NESHAP subpart AA) did not regulate fugitive HF emissions from gypsum dewatering stacks or cooling ponds. As explained in the preamble to the proposed rule, we are adopting a work practice standard instead of numeric emission limits because it is ''not feasible to prescribe or enforce an emission standard'' for these emissions because they ''cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant'' (see CAA section 112(h)(2)(A)) as the several hundred acres average size of these emission sources makes conveyance impractical. The size of these emission sources also makes it difficult to quantify the emission reductions that any control measure employed will achieve. However, in the paragraphs below, we explain how each control measure is feasible and effective in reducing fugitive HF emissions. We also provide details on the changes we have made to the gypsum dewatering stack and cooling pond management plan since proposal. Even after these changes, the measures are consistent with CAA section 112(d) controls and reflect a level of performance analogous to a MACT floor.

We noted in the preamble to the proposed rule that we believe that it is most effective for sources to determine the best practices that are to be incorporated into their site-specific gypsum dewatering stack and cooling pond management plan. We also stated in the preamble to the proposed rule that sources would be required to incorporate control measures from the list of options being proposed, and we solicited comment on the proposed site-specific gypsum dewatering stack and cooling pond management plan. In addition, we made considerable effort[5] before and after proposal in identifying a list of control measure options that encompass enough variety that at least one control measure option is feasible for at least one of each facility's existing gypsum dewatering stacks and/or cooling ponds. In fact, we are not aware

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[5] See the following documents which are all available in Docket ID No. EPA–HQ–OAR–2012–0522): ''USEPA Meeting with The Fertilizer Institute, July 24, 2013''; ''TFI meeting with USEPA to discuss RTR for Phosphoric Acid and Phosphate Fertilizer NESHAPs, September 11, 2014''; ''EPA Meeting Minutes for TFI Discussion March 12, 2015''; ''Summary of Potential Costs for Implementing Phosphate NESHAPs/ Recommendations for Phosphogypsum Stack Work Practices, May 5, 2015''; ''Notes from Meeting with Florida DEP Regarding Gypsum Dewatering Stack and Cooling Pond Management Plan, March 4, 2015''; and ''Site Visits to Mosaic Plant City and Mosaic New Wales, March 4, 2015.''

of any facility that does not use a rim ditch (cell) building technique. Therefore, we disagree with commenters that the options we have listed for the gypsum dewatering stack and cooling pond management plan are not technically feasible.

Additionally, personnel from the Florida Department of Environmental Protection (DEP) had concerns regarding how the plan would be implemented, as well as how a facility would show compliance with the control measure it chooses (see ''Notes from Meeting with Florida DEP Regarding Gypsum Dewatering Stack and Cooling Pond Management Plan, March 4, 2015,'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522). Therefore, in an effort to improve compliance demonstration with a facility's site-specific gypsum dewatering stack and cooling pond management plan, we are including a condition in the final NESHAP subpart AA rule that requires facilities to submit their plan for approval to the Administrator. Facilities will be required to provide details on how they plan to implement and show compliance with the control measure(s) that they choose. The Administrator will approve or disapprove the facility's site-specific gypsum dewatering stack and cooling pond management plan within 90 days after it is received. There may be a benefit to facilities and permitting authorities for the gypsum dewatering stack and cooling pond management plan and the title V major modification application to be submitted and reviewed at the same time. To change any of the information submitted in the plan, the facility must submit a revised plan 60 days before the change is to be implemented in order to allow time for review and approval by the Administrator before the change is implemented.

We are not including an option in the NESHAP subpart AA final rule, as commenters requested, that would provide a flexibility mechanism for facilities to use additional practices not codified during this rulemaking. This type of flexibility does not provide regulatory certainty that is needed for both industry and the EPA.

Although some commenters opposed using a submerged discharge pipe (with necessary siphon breaks to a level below the surface of the pond) as a fugitive HF emissions control measure, we believe submerging a discharge pipe can be appropriate and effective for reducing emissions from process water discharges into a cooling pond, although some facilities may not choose this option. Moreover, we agree with commenters that submerging siphon breaks could impede the ability of these devices to prevent backflow; therefore, we are removing this requirement from the final rule. On a recent site visit (see ''Site Visits to Mosaic Plant City and Mosaic New Wales, March 4, 2015,'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522), we noted strong vapor odors coming from splash operations occurring at a non-submerged pipe that was discharging process water into a cooling pond. According to AP–42, Chapter 5.2—Transportation and Marketing of Petroleum Liquids (01/95), significant turbulence and vapor/liquid contact that occur during splash discharge operations will result in higher levels of vapor generation and emissions loss compared to using a submerged discharge operation. Liquid turbulence is controlled significantly during submerged discharge operations, resulting in much lower vapor generation than encountered during splash discharge operations. We believe this demonstrates that submerging the pipe is an effective technique for mitigating HF emissions, and we are therefore retaining this option for cooling ponds.

However, we are removing the option of submerging a discharge pipe that is associated with the gypsum pond because it is not a feasible option due to high solids volume in the slurry. (A gypsum pond, also called a settling pond, often is located in the middle of a gypsum disposal pile and receives waste gypsum slurry.) Based on information received from industry after the public comment period ended for the proposal (see Docket ID No. EPA–HQ–OAR–2012–0522–0048), it is much more likely for this particular pipe to become clogged, creating backpressure on pump seals. Submerging the discharge pipe under water in the gypsum pond creates a potential restriction against the discharging slurry that could get worse as solids build up around and against the end of the pipe. The discharge pipe for the gypsum pond is also routinely moved, which complicates submersing it.

As we stated earlier in our response, we are not aware of any facility that uses a gypsum dewatering stack building technique that is different from rim ditch (cell) building. With regard to commenters' assertions that the EPA did not provide data or explain the link between minimizing the gypsum dewatering stack surface area and reducing fugitive HF emissions, we believe that using the rim ditch technique over the lifespan of a gypsum dewatering stack will reduce the surface area of the gypsum pond and thereby reduce fugitive HF emissions. Fugitive HF emissions are calculated using an emission factor that is directly related to the total acreage from the gypsum dewatering stack, which includes the pond surface area (tons HF per acre per year); therefore, minimizing the pond surface area would minimize HF emissions. The rim ditch (cell) building technique is mainly used for gypsum dewatering stack stability since inner and outer dikes are used to create a rim ditch that provides better protection against overflow of the gypsum pond. However, as rim ditches are filled with slurry, the gypsum pond area will gradually decrease within each cell, thereby shrinking the amount of surface area of the pond that is exposed to the atmosphere (reducing the amount of fugitive HF emissions). An alternative to the rim ditch technique is to simply discharge gypsum slurry into the gypsum pond. With this technique, there is no inner dike to control slurry flow and the pond surface area would not be reduced as quickly or consistently. This increased surface area would allow greater potential for fugitive HF emissions due to the larger amount of surface water exposed to the atmosphere. We are revising this control measure option in the NESHAP subpart AA final rule to clarify that owners or operators must minimize the surface area of the gypsum pond associated with the active gypsum dewatering stack (and not the surface area of the active gypsum dewatering stack as we had proposed) by using a rim ditch (cell) building technique or other building technique. This clarification also addresses industry's suggestion to reword the control measure in response to a meeting that occurred after the public comment period closed (see ''EPA Meeting Minutes for TFI Discussion March 12, 2015,'' and ''Summary of Potential Costs for Implementing Phosphate NESHAPs/Recommendations for Phosphogypsum Stack Work Practices, May 5, 2015,'' which are both available in Docket ID No. EPA–HQ–OAR–2012–0522). Moreover, in this same correspondence that occurred after the public comment period closed, industry provided a suggestion for the definition of ''rim ditch.'' We agree with industry's suggested definition; however, we believe the definition more appropriately covers the meaning of ''rim ditch (cell) building technique'' and not just ''rim ditch.'' We are including this definition in the final rule for ''rim ditch (cell) building technique'' in an effort to clarify what we mean by this control measure. The final rule defines ''rim ditch (cell) building technique'' as a gypsum dewatering stack construction technique that utilizes inner and outer dikes to direct gypsum slurry flow around the perimeter of the stack before directing the flow and allowing settling of finer materials into the settling compartment. For the purpose of this definition, the rim ditch (cell) building technique includes the compartment startup phase when gypsum is deposited directly into the settling compartment in preparation for ditch construction, as well as the step-in or terminal phases when most solids must be directed to the settling compartment prior to stack closure. Decant return ditches are not rim ditches.

Based on commenters' objection to wetting active gypsum dewatering stacks as a fugitive HF emissions control measure, and additional discussion with industry (see ''EPA Meeting Minutes for Simplot Discussion April 1, 2015,'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522), we determined that the proposed rule was not clear on how this control measure would be used. This control measure is not applied to the side slopes of the gypsum dewatering stacks, and instead is used on certain gypsum areas within cells of a gypsum dewatering stack. According to one facility located in arid climate (see ''EPA Meeting Minutes for Simplot Discussion April 1, 2015,'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522), these areas may be more susceptible to drying out in warmer months due to higher surface temperatures of the gypsum dewatering stack; therefore, a system of weirs can be used to help direct gypsum pond water (not fresh water) to these areas to keep them wet. We agree with the commenter who pointed out that that applying water to a gypsum stack may actually increase fugitive emissions because HF resides primarily in the water used to transport the gypsum slurry to the gypsum dewatering stack. We realize that this option might increase the surface area of the gypsum pond water which conflicts with our understanding that minimizing surface area of the gypsum pond will minimize HF emissions. Therefore, we are not adopting this proposed control measure in the NESHAP subpart AA final rule.

In response to a commenter's assertion that there is lack of evidence of the effectiveness of applying slaked lime to gypsum dewatering stacks as a fugitive HF emissions control measure, we received information after the public comment period ended (see Docket ID No. EPA–HQ–OAR–2012–0522–0048) that at least one facility uses this technique to help meet its state ambient air standard for F. This commenter stated that, based on data from their site-specific ambient air monitoring, they apply a lime solution to their gypsum dewatering stack areas during periods where they are close to violating their 30-day state ambient air standard for F, measured as HF, in order to stay below the standard. Slaked lime can precipitate fluorides from gypsum dewatering stacks and cooling ponds, thus reducing the availability of fluorides in solution that could then be released into the air during evaporation. This is an example of the type of detail that the Administrator may require be included in the facility's site-specific plan (in addition to how compliance would be demonstrated) before it could be approved. We have clarified in the final rule that if this control measure is chosen, then the plan must include the method used to determine the specific locations slaked lime is applied. The plan must also include the methods used to determine the quantity of, and when to apply, slaked lime (*e.g.,* slaked lime may be applied to achieve a state ambient air standard for F, measured as HF).

With respect to the measure involving application of soil caps and vegetation to side slopes of a gypsum dewatering stack, on recent site, visits personnel from Mosaic and the Florida DEP had concerns that this control measure was too specific in that it could be difficult for facilities to demonstrate compliance with the ''50 feet below the stack top'' requirement as well as the requirement to apply soil caps and vegetation to all side slopes (see ''Site Visits to Mosaic Plant City and Mosaic New Wales, March 4, 2015,'' and ''Notes from Meeting with Florida DEP Regarding Gypsum Dewatering Stack and Cooling Pond Management Plan, March 4, 2015,'' which are available in Docket ID No. EPA–HQ–OAR–2012–0522). We recognize that applying soil caps and vegetation to side slopes of a gypsum dewatering stack is an ongoing process that continuously changes over time based on facility-specific operations. Therefore, we have revised this control measure option in the NESHAP subpart AA final rule to acknowledge that this technique will only be applied to portions of the side slopes that are no longer active on a gypsum dewatering stack instead of all side slopes up to 50 feet below the top of the gypsum dewatering stack. We also have revised this option to allow the use of a synthetic cover in lieu of soil caps and vegetation. Furthermore, we expect that if a facility chose to use this specific control measure in their plan, the Administrator may require details on schedule, and how the portion of side slopes that received soil caps and vegetation, or a synthetic cover, is determined (in addition to how compliance would be demonstrated), before the plan could be approved. Therefore, we have clarified in the final rule that the plan must include the method used to determine the specific locations of soil caps and vegetation, or synthetic cover, and specify the acreage and locations where soil caps and vegetation, or synthetic cover, is applied. The plan must also include a schedule describing when soil caps and vegetation, or synthetic cover, is to be applied.

Additionally, we believe that this control measure creates a barrier on the surface of the gypsum dewatering stack side slopes that reduces HF emissions; therefore, we disagree with commenters' assertion that applying soil caps and vegetation may not be an effective option for fugitive HF emissions control. The Florida DEP has used this control measure as part of its overall management of fluorides from gypsum dewatering stacks; and Wyoming has approved this control measure in a facility's title V permit as an optional method for reducing fugitive fluoride emissions. We also disagree with a request[6] to reword this control measure to require a gypsum dewatering stack construction and operation plan because the commenter did not provide any justification on how this activity reduces fugitive HF emissions from gypsum dewatering stacks.

We disagree with commenters' requests to exclude closure from the list of measures for controlling fugitive HF emissions from gypsum dewatering stacks. We believe that closing a gypsum dewatering stack is one of the best solutions for reducing fugitive HF emissions because it permanently reduces the emissions from the greatest contributing source. However, we are revising this control measure option in the NESHAP subpart AA final rule to allow a facility to design its own closure requirement plan, provided that the closure requirements, at a minimum, contain: (1) A specific trigger mechanism for when owners or operators must begin the closure process on the gypsum dewatering stack, and (2) a requirement to install a final cover. As with all gypsum dewatering stack and

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[6] See ''EPA Meeting Minutes for TFI Discussion March 12, 2015,'' and ''Summary of Potential Costs for Implementing Phosphate NESHAPs/ Recommendations for Phosphogypsum Stack Work Practices, May 5, 2015,'' which are both available in Docket ID No. EPA–HQ–OAR–2012–0522.

cooling pond management plans, this closure requirement must be submitted to the Agency for approval. Although we are not identifying a specific trigger mechanism in the final rule, one example of a trigger mechanism is a facility-specified length of time where the gypsum dewatering stack is inactive and no longer receives gypsum (*i.e.,* once the gypsum dewatering stack stops receiving gypsum for a period of time, the facility must begin closing it). Also, we are clarifying that a final cover means the materials used to cover the top and sides of a gypsum dewatering stack upon closure. This addresses commenters request that the EPA should allow the final cover on a closed stack to consist of a synthetic liner. Finally, in light of our decision to revise the control measure option for closing a gypsum dewatering stack, we are also removing the definition of a ''closed gypsum dewatering stack'' from the NESHAP subpart AA final rule. Since the revised language relies on a specific trigger mechanism for when owners or operators must begin the closure process on the gypsum dewatering stack, the definition of a ''closed gypsum dewatering stack'' is no longer necessary in the final rule. Because we are removing the definition of a ''closed gypsum dewatering stack'' from the final rule, we are revising the definition of an ''active gypsum dewatering stack.'' In the NESHAP subpart AA final rule, an ''active gypsum dewatering stack'' means a gypsum dewatering stack that is currently receiving gypsum, received gypsum within the last year, or is part of the facility's water management system. A gypsum dewatering stack that is considered closed by a state authority is not considered an active gypsum dewatering stack.

As we have stated before, the final list of NESHAP subpart AA control measures is exhaustive enough that a facility has a number of options for selecting a control measure that would be feasible for their particular operations. We assume that facilities would choose the lowest cost option, and that all facilities are using at least one of the control measure options already (*e.g.,* we are not aware of any facilities that do not use a rim ditch (cell) building technique). Therefore, we disagree with the commenters' claim that enormous costs would be incurred if they were required to apply soil caps and vegetation to all side slopes of the active gypsum dewatering stack up to 50 feet below the stack top. We are not requiring that facilities implement this control measure since this specific control technique is not a requirement, but instead an option for how a facility may demonstrate compliance with the work practice standards for fugitive HF emissions from the gypsum management system.

iii. Requirement to Use At Least Two of the Fugitive HF Emissions Control Measures—Comment. One commenter requested that the EPA eliminate the ''dual practice'' approach for new sources. Two commenters declared that the requirement to implement ''at least two of the control techniques'' listed for ''each regulated gypsum dewatering stack and cooling pond'' is not possible without a broader list that includes at least two practices for cooling ponds. Additionally, with regard to closing an active gypsum dewatering stack as a control technique option, the commenter contended that giving an owner of a new gypsum dewatering stack the option of closing it in tandem with a mandatory second control technique is ''nonsensical'' because the ''new stack would immediately have to be closed to implement the practice.'' Another commenter wanted clarification as to whether the lateral expansion of an existing gypsum dewatering stack is considered a new stack, and thus would trigger the proposed work practice standards related to the size of active gypsum dewatering stacks and production ratio. The commenter also sought clarification as to whether at least two of the control techniques be used in the gypsum dewatering stack and cooling pond management plan for controlling fugitive HF emissions would be required.

Response. We agree with the commenter that the proposed requirement for new gypsum dewatering stacks and cooling ponds to implement ''at least two of the control techniques'' listed for ''each'' regulated ''gypsum dewatering stack and cooling pond,'' would make compliance for cooling ponds impossible for new sources without a broader list with at least two control measures for cooling ponds. In the final rule, the Agency is using the terminology ''control measures'' in lieu of the proposed terminology ''control techniques'' because it more accurately describes the list of options in the rule and avoids confusion with other CAA programs. As stated in a previous response, in an effort to clarify the specific emission source that we are regulating in the final rule (NESHAP subpart AA), we have included a new term, ''gypsum dewatering stack system,'' (see sections V.C.3.b.i of this preamble for further details) in the final rule. This revision also clarifies our original intent that the two control measure options that a facility selects can be for any combination of gypsum dewatering stacks and/or cooling ponds in the gypsum dewatering stack system. For example, if a facility operates a cooling pond considered a new source, the facility may choose to not implement the control measure option requiring a submerged discharge pipe for the new cooling pond, and instead implement two control measures at one or more gypsum dewatering stacks no matter whether they be considered a new or existing source. Furthermore, we have revised the control measure option for closing a gypsum dewatering stack (see section V.C.3.b.ii of this preamble for further details). Because of this change to the NESHAP subpart AA final rule, there is no longer a requirement to immediately close the active gypsum dewatering stack in tandem with a mandatory second control measure option.

Lastly, the Agency has revised the definitions in the NESHAP subpart AA final rule for when a gypsum dewatering stack is considered ''new'' or ''existing'' in order to address whether a lateral expansion of an existing gypsum dewatering stack is considered a new gypsum dewatering stack. The revised definitions in the final rule also deal with a concern one commenter raised during the comment period about triggering the proposed regulation for a ''new'' source each time they rotate the functionality of their three gypsum dewatering stack sites at their facility (this topic was also discussed after the comment period closed, see ''USEPA Meeting Minutes for PCS Aurora Discussion (2.2.2015),'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522). We are revising the NESHAP subpart AA final rule such that a gypsum dewatering stack or cooling pond is considered ''new'' if it meets two criteria: (1) It was constructed or reconstructed after August 19, 2015, and (2) it was required to obtain a permit by a state authority for the construction or reconstruction. Some lateral expansions may build beyond a facility's existing permitted capacity (and design dimensions of the gypsum dewatering stack); therefore, these lateral expansions would be considered ''new'' in the final rule because the facility would be required to obtain (or revise) their existing permitted capacity (and design dimensions). Because of this change in the NESHAP subpart AA final rule, we are also revising the criteria for when a gypsum dewatering stack or cooling pond is considered ''existing.'' Specifically, a gypsum dewatering stack or cooling pond is considered ‘‘existing’’ if it meets one of two criteria: (1) It was constructed or reconstructed on or before August 19, 2015, or (2) it was constructed or reconstructed after August 19, 2015 and it was not required to obtain a permit by a state authority for the construction or reconstruction.

iv. Fugitive HF Emissions Control Measure Considerations for Cooling Ponds—Comment. One commenter referenced a 1978 EPA document: ‘‘Evaluation of Emissions and Control Techniques for Reducing Fluoride Emissions from Gypsum Ponds in the Phosphoric Acid Industry’’ and questioned why the EPA proposed work practice standards focused solely on gypsum dewatering stacks, while the EPA has in the past studied and documented more work practices for controls of cooling pond emissions, which are not discussed as alternatives to the proposed rule. Another commenter requested that if EPA keeps cooling ponds as part of the gypsum dewatering stack and cooling pond management plan, then EPA should provide more than one work practice that could be implemented at a cooling pond. They suggested that EPA add a control measure option (for cooling ponds) that would require developing a plan to optimize the size of cooling ponds to address fugitive HF emissions (as appropriate based on the conditions at the facility).

In addition, another commenter suggested additional control measure options for reducing fugitive HF emissions from cooling ponds. This commenter suggested EPA include an option to develop and implement a plan for dredging cooling ponds which helps maintain cooling capacity, and, therefore, can reduce fugitive emissions by reducing the vapor pressure of fluoride in the pond water. This commenter also suggested EPA include an option to implement a system for the recovery of fluoride for water that is directed to cooling ponds. The commenter pointed out that one of its facilities has the capability to recover fluoride as hydrofluorosilicic acid during the phosphoric acid evaporation process. The commenter stated that this recovery process is operated as needed to meet the market demand for hydrofluorosilicic acid. Finally, the commenter suggested EPA include an option to implement a system for the removal of fluoride for water that is directed to cooling ponds (for example, by adding lime to increase the pH).

Response. We are aware of the 1978 EPA document, ‘‘Evaluation of Emissions and Control Techniques for Reducing Fluoride Emissions from Gypsum Ponds in the Phosphoric Acid Industry,’’ and the six potential control techniques it examines for reducing fluoride emissions from gypsum ponds. These six potential control techniques include: (1) Use of the ‘‘Kidde’’ process; (2) use of the ‘‘Swift’’ process; (3) use of lime to raise pH; (4) dry conveyance of gypsum, (5) pretreatment of ore by calcining; and (6) changing the entire phosphoric acid production process to a ‘‘hemi/dehydrate’’ process. The 1978 EPA document clarifies that the first four of these potential control techniques could also reduce fluoride emissions from cooling ponds. The ‘‘Swift,’’ ‘‘Kidde,’’ and ‘‘hemi/dehydrate’’ processes each use byproduct fluoride in the WPPA to produce hydrofluorosilicic acid (an acid generally used in fluoridation of drinking water, but also has other industry uses) or ammonium silicofluoride. We are aware of at least two facilities that are equipped and capable of making hydrofluorosilicic acid; however, it is not clear which process they use, nor is it clear if either facility is actively making hydrofluorosilicic acid. However, facilities have expressed that production of hydrofluorosilicic acid for the primary purpose of controlling HF emissions is not practical. Facilities that produce hydrofluorosilicic acid seek to sell the product for use in water fluoridation.[7] In fact, one commenter stated that their recovery process is operated as needed to meet the market demand for hydrofluorosilicic acid. Facilities would not produce this product in the absence of a market demand, as the hydrofluorosilicic acid would be another waste stream that would need to be disposed of. Therefore, we do not believe this to be a reasonable control technique option for fugitive HF emissions from these sources.

We have determined that using lime (or any other caustic substance) to raise the pH of liquid discharged into the cooling pond could be a feasible control measure option for reducing fluoride emissions from cooling ponds; therefore, we are including this option in the NESHAP subpart AA final rule. The control measure option simultaneously raises the pH of the cooling pond water and lowers the concentration of soluble F, and, thus reducing the concentration of fluoride (including HF) that could be potentially evaporated into the atmosphere. Based on information provided in the 1978 EPA document, a greater than 90 percent emission reduction in fluoride can be achieved by raising the pond water from pH 1.4 to pH 3.9. In the final rule, if this control measure is chosen, then the plan must include: the method used to raise the pH of the liquid discharged into the cooling pond, the target pH value (of the liquid discharged into the cooling pond) expected to be achieved by using the method, and the analyses used to determine and support the raise in pH. Moreover, this control measure is similar to an option that industry suggested in response to a meeting that occurred after the public comment period closed (see ‘‘EPA Meeting Minutes for TFI Discussion March 12, 2015,’’ and ‘‘Summary of Potential Costs for Implementing Phosphate NESHAPs/Recommendations for Phosphogypsum Stack Work Practices, May 5, 2015,’’ which are both available in Docket ID No. EPA–HQ–OAR–2012–0522). Industry suggested including an option that would require providing inputs to the gypsum dewatering stack system to react with and precipitate fluoride compounds to insoluble forms.

With regard to the remaining potential control techniques identified in the 1978 EPA document (*i.e.,* dry conveyance of gypsum and pretreatment of ore by calcining), we have determined that these control techniques are not likely to be used by industry because significant process changes would be required. Furthermore, with regard to pretreatment of ore by calcining, the 1978 EPA document states that off-gases from pretreating ore would still need to be scrubbed to remove F, and the scrubbing liquid from this process would likely be disposed of in a cooling pond (which would defeat the purpose of this technique). Therefore, we are not finalizing the NESHAP subpart AA final rule to include these two control measure options for controlling fugitive HF emissions from cooling ponds.

Lastly, we agree with a commenter’s request to add a control measure option (for cooling ponds) that would require developing a plan to optimize the size of cooling ponds to address fugitive HF emissions (as appropriate based on the conditions at the facility); therefore, we are including this option in the NESHAP subpart AA final rule. However, in order for a facility to be able to use this control measure option, its cooling pond evaluation must result in a reduction in overall cooling pond surface area. Fugitive HF emissions are calculated using an emission factor that is directly related to gypsum dewatering stack and pond surface area (tons HF per acre per year); therefore, minimizing

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[7] *http://www.cdc.gov/fluoridation/factsheets/engineering/wfadditives.htm.*

the surface area of the cooling pond(s) would minimize HF emissions. On a recent site visit (see ''Site Visits to Mosaic Plant City and Mosaic New Wales, March 4, 2015,'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522), we noticed that one company evaluated whether a reduction in the size of its cooling ponds could still support additional water due to rainfall and plant process water needs. However, the result of these evaluations did not lead to a change in size of its cooling ponds, and thus did not lead to a reduction in fugitive HF emissions from the cooling ponds. In the final rule, if this control measure is chosen, then the facility-specific evaluation plan must be certified by an independent licensed professional engineer or similarly qualified individual, and include the method used to reduce the total cooling pond footprint, the analyses used to determine and support the reduction in the total cooling pond surface area, and the amount of total cooling pond surface area that was reduced due to the facility-specific evaluation plan. Furthermore, we agree with the commenter who stated dredging cooling ponds is a good practice for maintaining cooling capacity. With regard to the commenter's request to include this activity (*i.e.,* dredging cooling ponds) as a specific control measure option,[8] we determined that this activity could be considered in the cooling pond evaluation; however, the evaluation would still need to lead to a change in size of the surface area of the cooling pond for it to qualify as a control measure in the final rule.

We also evaluated an additional control measure option suggested by industry in response to a meeting that occurred after the public comment period closed (see ''EPA Meeting Minutes for TFI Discussion March 12, 2015,'' and ''Summary of Potential Costs for Implementing Phosphate NESHAPs/Recommendations for Phosphogypsum Stack Work Practices, May 5, 2015,'' which are both available in Docket ID No. EPA–HQ–OAR–2012–0522). Industry suggested including the option to ''operate the cooling pond systems to adjust the active cooling surface area to address weather conditions, seasonal cooling needs and associated production changes. Cooling circuit adjustments may be accomplished through utilization of either fixed or floating flow diversion devices or by changing flows such that some of the heated water is diverted away from portions of the ponded area.'' However, we are not including this option in the final rule because it is not clear how the option reduces fugitive HF emissions from cooling ponds.

v. Excluding Cooling Ponds from Management Plan—Comment. One commenter requests that the EPA revise the regulatory language in proposed 40 CFR 63.602 (d) through (f) that refers to each ''gypsum dewatering stack and cooling pond'' to instead refer only to each ''gypsum dewatering stack.'' The commenter stated that the regulatory direction seems to encompass ponds that are not part of a ''gypsum dewatering stack.'' Another commenter claimed the rule implies that control measure options apply to cooling ponds distinctly from gypsum dewatering stacks. An additional commenter alleged that work practice standards should not apply to cooling ponds that are physically separate from gypsum stacks. This commenter pointed out that only one practice (submerging the discharge pipe) relates to cooling ponds, and because of the requirement to implement at least one practice for each ''gypsum dewatering stack and cooling pond,'' then cooling ponds that fall within the proposed definition of a gypsum dewatering stack seemingly could choose to submerge the discharge pipe at the pond, or they could implement other techniques from the list.

Response. The NESHAP subpart AA final rule clarifies that the gypsum dewatering stack and cooling pond management plan is intended to cover both gypsum dewatering stacks and cooling ponds. In response to a previous comment, we have included a new term ''gypsum dewatering stack system,'' revised the definition of ''gypsum dewatering stack'' to exclude cooling ponds, and have retained the proposed definition of ''cooling pond'' in the final rule (see section V.C.3.b.i of this preamble for further details).

4. What is the rationale for our final approach pursuant to CAA sections 112(d)(2), 112(d)(3), and 112(h)?

For the reasons provided above and in the preamble for the proposed rule, we are finalizing our proposal to eliminate the use of PM as a surrogate for Hg and are adding Hg and total fluoride emission limits for phosphate rock calciners to the NESHAP subpart AA final rule.

For the reasons provided above, we are making the revisions, clarifications, and corrections noted in section V.C.2 in the NESHAP subpart AA final rule.

D. NSPS Review for the Phosphoric Acid Manufacturing Source Category

The NSPS review focused on the emission limitations that have been adequately demonstrated to be achieved in practice, taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements. Determining the BSER that has been adequately demonstrated and the emission limitations achieved in practice necessarily involves consideration of emission reduction methods in use at existing phosphoric acid manufacturing plants. To determine the BSER, the EPA performed an extensive review of several recent sources of information, including a thorough search of the RACT/BACT/LAER Clearinghouse (RBLC), section 114 data received from industry, and other relevant sources.

Our review considered the emission limitations that are currently achieved in practice, and found that more stringent standards are not achievable for this source category. When evaluating the emissions from various process lines, we observed differences in emissions levels, but did not identify any patterns in emission reductions based on control technology configuration. More information concerning our NSPS review can be found in the memorandum, ''CAA Section 111(b)(1)(B) and 112(d)(6) Reviews for the Phosphoric Acid Manufacturing and Phosphate Fertilizer Production Source Categories.'' Though some of the sources are emitting at levels well below the current NSPS, other sources are not. We evaluated emissions based on control technologies and practices used by facilities, and found that the same technologies and practices yielded different results for different facilities. Therefore, we determined that we cannot conclude that new and modified sources would be able to achieve a more stringent NSPS. As explained in the proposed rule, all Phosphoric Acid Manufacturing NSPS (under subpart T and subpart U) emission sources, and the control technologies that would be employed, are the same as those for the NESHAP regulating phosphoric acid plants, such that we reached the same conclusion that there are no identified developments in technology or practices that results in cost-effective emission

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[8] Industry also suggested this control measure as an option to reducing fugitive HF emissions from cooling ponds in response to a meeting that occurred after the public comment period closed (see ''EPA Meeting Minutes for TFI Discussion March 12, 2015,'' and ''Summary of Potential Costs for Implementing Phosphate NESHAPs/Recommendations for Phosphogypsum Stack Work Practices, May 5, 2015,'' which are both available in Docket ID No. EPA–HQ–OAR–2012–0522).

reductions strategies. Therefore, we are finalizing our determination that revisions to NSPS subpart T and subpart U standards are not appropriate pursuant to CAA section 111(b)(1)(B).

E. Startup, Shutdown, and Malfunction Provisions for the Phosphoric Acid Manufacturing Source Category

1. What SSM provisions did we propose for the Phosphoric Acid Manufacturing source category?

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the U.S. Court of Appeals for the District of Columbia Circuit vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), holding that under section 302(k) of the CAA, emissions standards or limitations must be continuous in nature and that the SSM exemption violates the CAA's requirement that some CAA section 112 standards apply continuously.

We proposed to eliminate the SSM exemption in NESHAP subpart AA. Consistent with *Sierra Club* v. *EPA,* the EPA proposed standards in this rule that apply at all times. We also proposed to revise appendix A of subpart AA (the General Provisions Applicability Table) in several respects as is explained in more detail below. For example, we proposed to eliminate the incorporation of the General Provisions' requirement that the source develop an SSM plan. We also proposed to eliminate and revise certain recordkeeping and reporting related to the SSM exemption as described in detail in the proposed rule and summarized again here.

In proposing the standards in this rule, the EPA took into account startup and shutdown periods and, for the reasons explained below, proposed work practice standards for periods of startup and shutdown in lieu of numeric emission limits. CAA section 112(h)(1) states that the Administrator may promulgate a design, equipment or operational work practice standard in those cases where, in the judgment of the Administrator, it is not feasible to prescribe or enforce an emission standard. CAA section 112(h)(2)(B) further defines the term ''not feasible'' in this context to apply when ''the application of measurement technology to a particular class of sources is not practicable due to technological and economic limitations.''

Startup and shutdown periods at phosphoric acid manufacturing facilities generally only last between 30 minutes and 6 hours. Because of the variability and the relatively short duration, compared to the time needed to conduct a performance test, which typically requires a full working day, the EPA has determined that it is not feasible to prescribe a numeric emission standard for these periods. Furthermore, according to information provided by industry, it is possible that the feed rate (*i.e.,* equivalent P_2O_5 feed, or rock feed) can be zero during startup and shutdown periods. During these periods, it is not feasible to consistently enforce the emission standards that are expressed in terms of lb of pollutant/ton of feed.

Although we requested information on emissions and the operation of control devices during startup and shutdown periods in the CAA section 114 survey issued to the Phosphoric Acid Manufacturing source category, we did not receive any emissions data collected during a startup and shutdown period (nor did we receive data during public comment of the proposed rule), and we do not expect that these data exist. However, based on the information for control device operation received in the survey, we concluded that the control devices could be operated normally during periods of startup or shutdown. Also, we believe that the emissions generated during startup and shutdown periods are lower than during steady-state conditions because the amount of feed materials introduced to the process during those periods is lower compared to normal operations. Therefore, if the emission control devices are operated during startup and shutdown, then HAP emissions will be the same or lower than during steady-state operating conditions.

Consequently, we proposed a work practice standard rather than an emissions limit for periods of startup or shutdown. We proposed that control devices used on the various process lines in this source category are effective at achieving desired emission reductions immediately upon startup; therefore, during startup and shutdown periods, we proposed that sources begin operation of any control device(s) in the production unit prior to introducing any feed into the production unit. We also proposed that sources must continue operation of the control device(s) through the shutdown period until all feed material has been processed through the production unit.

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 (40 CFR 63.2) (definition of malfunction). The EPA interprets CAA section 112 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 112 standards. Under CAA section 112, emission standards for new sources must be no less stringent than the level ''achieved'' by the best controlled similar source and for existing sources generally must be no less stringent than the average emission limitation ''achieved'' by the best performing 12 percent of sources in the category. There is nothing in CAA section 112 that directs the EPA to consider malfunctions in determining the level ''achieved'' by the best performing sources when setting emission standards. As the U.S. Court of Appeals for the District of Columbia Circuit has recognized, the phrase ''average emissions limitation achieved by the best performing 12 percent of'' sources ''says nothing about how the performance of the best units is to be calculated.'' *Nat'l Ass'n of Clean Water Agencies* v. *EPA,* 734 F.3d 1115, 1141 (D.C. Cir. 2013). While the EPA accounts for variability in setting emission standards, nothing in CAA section 112 requires the Agency to consider malfunctions as part of that analysis. A malfunction should not be treated 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 EPA to consider such events in setting CAA section 112 standards.

Further, accounting for malfunctions in setting emission standards would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not ''reasonably'' foreseeable. See, *e.g., Sierra Club* v. *EPA,* 167 F.3d 658, 662 (D.C. Cir. 1999) (''The EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to 'invest the resources to conduct the perfect study.' ''). See also *Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978) (''In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.''). In addition, emissions during a malfunction event can be significantly higher than emissions at any other time of source operation. For example, if an air pollution control device with 99 percent removal goes off-line as a result of a malfunction (as might happen if, for example, the bags in a baghouse catch fire) and the emission unit is a steady-state type unit that would take days to shutdown, the source would go from 99 percent control to zero control until the control device was repaired. The source's emissions during the malfunction would be 100 times higher than during normal operations, and the emissions over a 4-day malfunction period would exceed the annual emissions of the source during normal operations. As this example illustrates, accounting for malfunctions could lead to standards that are not reflective of (and significantly less stringent than) levels that are achieved by a well-performing non-malfunctioning source. It is reasonable to interpret CAA section 112 to avoid such a result. The EPA's approach to malfunctions is consistent with CAA section 112 and is a reasonable interpretation of the statute.

In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, sudden, infrequent, not reasonably preventable and was not instead caused in part by poor maintenance or careless operation 40 CFR 63.2 (definition of malfunction).

If the EPA determines in a particular case that an enforcement action against a source for violation of an emission standard is warranted, the source can raise any and all defenses in that enforcement action, and the federal district court will determine what, if any, relief is appropriate. The same is true for citizen enforcement actions. Similarly, the presiding officer in an administrative proceeding can consider any defense raised and determine whether administrative penalties are appropriate.

In summary, the EPA interpretation of the CAA and, in particular, CAA section 112 is reasonable and encourages practices that will avoid malfunctions. Administrative and judicial procedures for addressing exceedances of the standards fully recognize that violations may occur despite good faith efforts to comply and can accommodate those situations.

To address the U.S. Court of Appeals for the District of Columbia Circuit vacatur of portions of the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM, *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), we proposed to revise and add certain provisions to the Phosphoric Acid Manufacturing rule. As described in detail below, we proposed to revise the General Provisions table (appendix A) to change several references related to requirements that apply during periods of SSM. We also proposed to add other provisions to the Phosphoric Acid Manufacturing rule as described below.

a. 40 CFR 63.608(b) General Duty. We proposed to revise the entry for 40 CFR 63.6(e)(1)(i) and (e)(1)(ii) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' Section 63.6(e)(1)(i) describes the general duty to minimize emissions. Some of the language in that section is no longer necessary or appropriate in light of the elimination of the SSM exemption. We proposed instead to add general duty regulatory text at 40 CFR 63.608(b) that reflects the general duty to minimize emissions while eliminating the reference to periods covered by an SSM exemption. The current language in 40 CFR 63.6(e)(1)(i) characterizes what the general duty entails during periods of SSM. With the elimination of the SSM exemption, there is no need to differentiate between normal operations, startup and shutdown and malfunction events in describing the general duty. Therefore, the language the EPA proposed does not include that language from 40 CFR 63.6(e)(1). We also proposed to revise the entry for 40 CFR 63.6(e)(1)(ii) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' Section 63.6(e)(1)(ii) imposes requirements that are not necessary with the elimination of the SSM exemption or are redundant of the general duty requirement being added at 40 CFR 63.608(b).

b. SSM Plan. We proposed to revise the entry for 40 CFR 63.6(e)(3) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' Generally, these paragraphs require development of an SSM plan and specify SSM recordkeeping and reporting requirements related to the SSM plan. As noted, the EPA proposed to remove the SSM exemptions. Therefore, affected units will be subject to an emission standard during such events. The applicability of a standard during such events will ensure that sources have ample incentive to plan for and achieve compliance and thus the SSM plan requirements are no longer necessary.

c. Compliance with Standards. We proposed to revise the entry for 40 CFR 63.6(f) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' The current language of 40 CFR 63.6(f)(1) exempts sources from non-opacity standards during periods of SSM. As discussed above, the Court in Sierra Club v. EPA vacated the exemptions contained in this provision and held that the CAA requires that some CAA section 112 standard apply continuously. Consistent with Sierra Club v. EPA, the EPA proposed to revise standards in this rule to apply at all times.

d. 40 CFR 63.606 Performance Testing. We proposed to revise the entry for 40 CFR 63.7(e)(1) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' Section 63.7(e)(1) describes performance testing requirements. The EPA instead proposed to add a performance testing requirement at 40 CFR 63.606(d). The performance testing requirements that were proposed differ from the General Provisions performance testing provisions in several respects. The proposed regulatory text does not allow testing during startup, shutdown, or malfunction. The proposed regulatory text does not include the language in 40 CFR 63.7(e)(1) that restated the SSM exemption and language that precluded startup and shutdown periods from being considered ''representative'' for purposes of performance testing. Furthermore, as in 40 CFR 63.7(e)(1), performance tests conducted under this subpart should not be conducted during malfunctions because conditions during malfunctions are often not representative of operating conditions.

e. Monitoring. We proposed to revise the entry for 40 CFR 63.8(c)(1)(i) and (iii) in the General Provisions table by changing the ''yes'' in column three to ''no.'' The cross-references to the general duty and SSM plan requirements in those subparagraphs are not necessary in light of other requirements of 40 CFR 63.8 that require good air pollution control practices (40 CFR 63.8(c)(1)) and that set out the requirements of a quality control program for monitoring equipment (40 CFR 63.8(d)).

We proposed to revise the entry for 40 CFR 63.8(d)(3) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' The final sentence in 40 CFR 63.8(d)(3) refers to the General Provisions' SSM plan requirement, which is no longer applicable. The EPA proposed to add to the rule at 40 CFR 63.608(c)(3) text that is identical to 40 CFR 63.8(d)(3), except that the final sentence is replaced with the following sentence: ''You must include the program of corrective action required under § 63.8(d)(2) in the plan.''

f. 40 CFR 63.607 Recordkeeping. We proposed to revise the entry for 40 CFR 63.10(b)(2)(i) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' Section 63.10(b)(2)(i) describes the recordkeeping requirements during startup and shutdown. These recording provisions are no longer necessary because the EPA proposed that recordkeeping and reporting applicable to normal operations will apply to startup and shutdown. In the absence of special provisions applicable to startup and shutdown, such as a startup and shutdown plan, there is no reason to retain additional recordkeeping for startup and shutdown periods.

We proposed to revise the entry for 40 CFR 63.10(b)(2)(ii) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' Section 63.10(b)(2)(ii) describes the recordkeeping requirements during a malfunction. The EPA proposed to add such requirements to 40 CFR 63.607(b). The regulatory text we proposed to add differs from the General Provisions it is replacing in that the General Provisions requires the creation and retention of a record of the occurrence and duration of each malfunction of process, air pollution control and monitoring equipment. The EPA proposed that this requirement apply to any failure to meet an applicable standard and that the source record the date, time and duration of the failure rather than the ''occurrence.'' The EPA also proposed to add to 40 CFR 63.607(b) a requirement that sources keep records that include a list of the affected source or equipment and actions taken to minimize emissions, an estimate of the volume of each regulated pollutant emitted over the applicable standard and a description of the method used to estimate the emissions. Examples of such methods would include product-loss calculations, mass balance calculations, measurements when available or engineering judgment based on known process parameters. The EPA proposed requiring that sources keep records of this information to ensure that there is adequate information to allow the EPA to determine the severity of any failure to meet a standard, and to provide data that may document how the source met the general duty to minimize emissions when the source has failed to meet an applicable standard.

We proposed to revise the entry for 40 CFR 63.10(b)(2)(iv) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' When applicable, the provision requires sources to record actions taken during SSM events when actions were inconsistent with their SSM plan. The requirement is no longer appropriate because SSM plans will no longer be required. The requirement previously applicable under 40 CFR 63.10(b)(2)(iv)(B) to record actions to minimize emissions and record corrective actions is now applicable by reference to 40 CFR 63.607.

We proposed to revise the entry for 40 CFR 63.10(b)(2)(v) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' When applicable, the provision requires sources to record actions taken during SSM events to show that actions taken were consistent with their SSM plan. The requirement is no longer appropriate because SSM plans will no longer be required.

We proposed to revise the entry for 40 CFR 63.10(c)(15) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' The EPA proposed that 40 CFR 63.10(c)(15) no longer apply. When applicable, the provision allows an owner or operator to use the affected source's SSM plan or records kept to satisfy the recordkeeping requirements of the SSM plan, specified in 40 CFR 63.6(e), to also satisfy the requirements of 40 CFR 63.10(c)(10) through (12). The EPA proposed to eliminate this requirement because SSM plans would no longer be required, and, therefore, 40 CFR 63.10(c)(15) no longer serves any useful purpose for affected units.

g. 40 CFR 63.607 Reporting. We proposed to revise the entry for 40 CFR 63.10(d)(5) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' Section 63.10(d)(5) describes the reporting requirements for startups, shutdowns and malfunctions. To replace the General Provisions reporting requirement, the EPA proposed to add reporting requirements to 40 CFR 63.607. The replacement language differs from the General Provisions requirement in that it eliminates periodic SSM reports as a stand-alone report. We proposed language that requires sources that fail to meet an applicable standard at any time to report the information concerning such events in the excess emission report already required under this rule. We proposed that the report must contain the number, date, time, duration and the cause of such events (including unknown cause, if applicable), a list of the affected source or equipment, an estimate of the volume of each regulated pollutant emitted over any emission limit, and a description of the method used to estimate the emissions (*e.g.,* product-loss calculations, mass balance calculations, direct measurements or engineering judgment based on known process parameters). The EPA proposed this requirement to ensure that adequate information is available to determine compliance, to allow the EPA to determine the severity of the failure to meet an applicable standard, and to provide data that may document how the source met the general duty to minimize emissions during a failure to meet an applicable standard.

The proposed rule eliminates the cross reference to 40 CFR 63.10(d)(5)(i) that contains the description of the previously-required SSM report format and submittal schedule from this section. We proposed that these specifications would no longer be necessary because the events will be reported in otherwise required reports with similar format and submittal requirements. We proposed that owners or operators no longer be required to determine whether actions taken to correct a malfunction are consistent with an SSM plan because the plans would no longer be required.

We proposed to revise the entry for 40 CFR 63.10(d)(5)(ii) in the General Provisions table (appendix A) by changing the ''yes'' in column three to ''no.'' Section 63.10(d)(5)(ii) describes an immediate report for SSM when a source failed to meet an applicable standard but did not follow the SSM plan. We proposed that we would no longer require owners and operators to report when actions taken during a startup, shutdown, or malfunction were not consistent with an SSM plan because the plans would no longer be required.

2. How did the SSM provisions change for the Phosphoric Acid Manufacturing source category?

We are finalizing the proposed work practice standards for periods of startup and shutdown; however, in consideration of comments received during the public comment period for the proposed rulemaking (as discussed in sections V.E.3.a and V.E.3.b of this preamble), we are making changes to this work practice in order to clarify the standard applies in lieu of numeric emission limits and to clarify how compliance with the standard is demonstrated. Additionally, as discussed in section V.E.3.c of this preamble, we added a definition of ''startup'' and ''shutdown'' in the final rule to specify when startup begins and ends, and when shutdown begins and ends.

3. What key comments did we receive on the SSM provisions, and what are our responses?

We received comments regarding the proposed revisions to remove the SSM exemptions for the Phosphoric Acid Manufacturing source category, and the proposed work practice standards for periods of startup and shutdown. The following is a summary of some of the comments specific to the proposed work practice standards and our response to those comments. Other comments and our specific responses to those comments can be found in the Comment Summary and Response document available in the docket for this action (EPA–HQ–OAR–2012–0522).

a. Work Practice Standard In Place Of Emission Limits—Comment. One commenter argued that the EPA should specify that the proposed work practices for plant startup and shutdown periods apply ''in lieu of'' any other emission standards, and that such periods should not be counted for testing, monitoring, or operating parameter requirements. The commenter noted that the proposed rule at 40 CFR 63.602(h) requires the use of work practices ''to demonstrate compliance with any emission limits'' during periods of startup and shutdown. The commenter agrees with the EPA's conclusion that it is not feasible to apply numeric limits to startup and shutdown because certain variables required to calculate emissions would be zero during such periods. The commenter also agreed with the EPA that existing emission control devices would still be effective during periods of startup or shutdown, if activated. However, the commenter recommended that the rule should clarify that startup and shutdown events should not be required to comply with the monitoring and operating parameter requirements because startup and shutdown events generally are not representative of operating conditions for other compliance purposes, such as emissions testing. Instead, the commenter, as well as a second commenter, recommended that, because the startup and shutdown periods are not representative, the rule should only require that (1) all emission control devices be kept active, and (2) owners and operators follow the general duty to control emissions, and owners and operators should not be required to monitor operating parameters during startup and shutdown periods.

The commenter argued that the approach in the proposed rule at 40 CFR 63.602(h) to require the use of work practices ''to demonstrate compliance with any emission limits'' during periods of startup and shutdown is ''directly inconsistent'' with the approach that the EPA has applied to other source categories, where such practices clearly were prescribed ''in lieu of'' numeric emission limits that would otherwise apply. (The commenter cites, for example, 78 FR 10015, February 12, 2013.) According to the commenter, the EPA made it clear in other industries' rules that such work practice standards apply ''in place of'' or ''in lieu of'' numeric standards, including with respect to monitoring and recordkeeping requirements. (See id. at 10013 and 10015.) The commenter argues that according to the preamble language cited for those other industries, ''there will no longer be a numeric emission standard applicable during startup and shutdown,'' and the EPA recognizes that ''the recordkeeping requirement must change to reflect the content of the work practice standard''(Id. at 10014).

Therefore, the commenter recommended that the EPA should clearly explain that work practices are not applied to ''demonstrate compliance'' with numeric limits under subpart AA, which the EPA acknowledges are ''not feasible'' for startup and shutdown periods, and, instead, the work practices should be written to apply ''in lieu of'' the numeric limits during those periods. The commenter argues that without this clarification, it will appear that both the numeric standards and the work practice standards would apply during startup and shutdown. The commenter suggests that this can be corrected in the rule by using the ''in lieu of'' language used for other industries.

Response. The commenter is correct that our intention at proposal was that the numeric emission limits would not apply during periods of startup and shutdown, but that facilities would comply with the work practice instead. We did not intend for the work practice to be a method to demonstrate compliance with the emission limit. We are replacing the phrasing ''to demonstrate compliance'' with ''in lieu of'' as this language is more consistent with our original intent. Accordingly, in the final rule, 40 CFR 63.602(f) specifies that the emission limits of 40 CFR 63.602(a) do not apply during periods of startup and shutdown. Instead, owners and operators must follow the work practice specified in 40 CFR 63.602(f). See section V.E.3.b of this preamble for our response to commenters' argument that owners and operators should not be required to monitor operating parameters during startup and shutdown periods.

b. Applicability Of Operating Limits—Comment. Two commenters recommended that the EPA amend the rule to make clear that the work practice standards for startup and shutdown also apply in lieu of the parametric monitoring requirements set forth in subpart AA and make explicit that parametric operating requirements do not apply during times of startup and shutdown.

One commenter argued that when the EPA established the flow rate and pressure drop parametric monitoring requirements in its 1999 final rule, the EPA concluded that requiring continuous monitoring of these parameters ''help[ed] assure continuous compliance with the emission limit'' (64 FR 31365, June 10, 1999). The commenter also asserted that the rules specify that ''[t]he emission limitations and operating parameter requirements of this subpart do not apply during periods of startup, shutdown, or malfunction . . .'' (40 CFR 63.600(e)). The commenter argued that this was a reasonable action because the operating parameter ranges are established during annual performance tests, and these tests cannot be performed during startup and shutdown conditions.

The commenter suggested that in the proposed rule, the EPA exempted compliance with the emission limits during startup and shutdown periods, imposed work practice standards in lieu thereof, and retained the prohibition on conducting a performance test during periods of startup or shutdown (79 FR 66570 (proposed 40 CFR 63.606(d)). The commenter suggested that the proposed rule is silent on the applicability of the parametric monitoring requirements during startup and shutdown. The commenter asserted that because the parametric monitoring provisions provide an inference of compliance with the emission limits (64 FR 31365, June 10, 1999), and these emission limits do not apply during startup and shutdown, the commenter concluded that the parametric monitoring provisions similarly should not apply during startups and shutdowns.

The commenters pointed to two recent EPA NESHAP rulemakings to support their conclusion. First, the commenters argued that in its industrial, commercial and institutional boilers and process heaters NESHAP reconsideration proposal (hereinafter, the ''Boiler NESHAP''), the EPA, responding to a comment soliciting clarification ''that the operating limits and opacity limits do not apply during periods of startup and shutdown,'' stated that with the finalization of work practice standards, ''EPA agrees that the requested clarification is what was intended in the final rule'' (76 FR 80598 and 80615, December 23, 2011). The commenters asserted that to this end, in its response to the reconsideration, the EPA made clear that affected sources must comply with ''all applicable emissions and operating limits at all times the unit is operating except for periods that meet the definitions of startup and shutdown in this subpart, during which times you must comply with these work practices'' (78 FR 7138 and 7142, January 31, 2013). The commenters noted that in the Boiler NESHAP regulations, the EPA required the implementation of work practice standards in lieu of compliance with the operating parameter requirements during startup and shutdown by (1) Excluding periods of startup and shutdown from the averaging period (Id. at 7187, 40 CFR 63.7575, the definition of a 30-day rolling average'' excludes ''hours during startup and shutdown''), and (2) expressly stating that the ''standards'' (the emission limits and operating requirements) do not apply during periods of startup or shutdown. (Id. at 7163, 40 CFR 63.7500(f), titled ''What emission limitations, work practice standards, and operating limits must I meet?'' applies ''at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 of this subpart.'')

Second, the commenters argued that in its Portland Cement NESHAP, the EPA specified an operating limit for kilns, identified as a temperature limit established during a performance test, and that the temperature limit applied at all times the raw mill is operating, ''except during periods of startup and shutdown'' (78 FR 10039, February 12, 2013, 40 CFR 63.1346(a)(1)). Further, for the continuous monitoring requirements, including operating limits, the Portland Cement NESHAP required operating of the monitoring system at all times the affected source is operating, ''[e]xcept for periods of startup and shutdown'' (Id. at 10041, 40 CFR 63.1348(b)(1)(ii)).

The commenters argued that given the EPA's conclusion in the proposed rule that the emission limits should not apply during startup and shutdown, and because the parametric monitoring requirements are established during a performance test (which cannot be performed during a startup or a shutdown) and used to infer compliance with the emission limits, the EPA should make clear in the final rule that the operating parameters requirements do not apply during startup or shutdown. The commenter recommended that the EPA should make this explicit: (1) In the operating and monitoring requirement section of subpart AA (proposed 40 CFR 63.605), and (2) by defining the averaging period (currently daily) as excluding periods of startup and shutdown (proposed 40 CFR part 63, subpart AA, Table 4.) As an alternative, the commenters recommended that if the EPA continues to require compliance with the parametric monitoring requirements during startup and shutdown periods, then the EPA should adopt a longer averaging period, from daily to 30 days, to allow for the effects of startups and shutdowns to be reduced by a longer period of steady-state operations. The commenter noted that the Boiler NESHAP has a 30-day averaging period for pressure drop and liquid flow rate, and excludes periods of startup and shutdown from the averaging period (40 CFR 63.7575, definition of ''30-day rolling average'' and 40 CFR part 63, subpart DDDDD, Table 4.) The commenter stated that a 30-day averaging period would be substantially more stringent than the Boiler NESHAP approach since it would include periods of startup and shutdown, while at the same time avoid misleading ''exceedances'' caused by the inclusion of periods of startup and shutdown compared to daily average parametric limits.

Response. We disagree with the commenters about the applicability of the operating limits. Based on these comments, we have clarified in the final rule at 40 CFR 63.602(f) that to comply with the work practice during periods of startup and shutdown, facilities must monitor the operating parameters specified in Table 3 to subpart AA and comply with the operating limits specified in Table 4 of subpart AA. The purpose of the work practice is to ensure that the air pollution control equipment that is used to comply with the emission limit during normal operations is operated during periods of startup and shutdown. Monitoring of control device operating parameters is necessary to demonstrate compliance with the work practice. We have concluded that it is reasonable for the control device at phosphoric acid processes to meet the same operating limits during startup and shutdown that apply during normal operation, and that it is not necessary to specify different averaging times for periods of startup and shutdown. Meeting the operating limits of Table 4 of subpart AA will ensure that owners and operators meet the General Duty requirement to operate and maintain the affected source and associated air pollution control equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions.

The analogies that the commenters made to the Industrial Boiler NESHAP and the Portland Cement NESHAP are not relevant to this rulemaking. In each rulemaking, we consider the feasibility of applying standards during startup and shutdown based on relevant process considerations for each source category, the pollutants regulated, and control devices on which the rule is based. In developing this rule, we obtained information on the operation of control devices during startup and shutdown periods in the CAA section 114 survey issued to the phosphoric acid manufacturing industry. Based on survey results, we concluded that for this source category, control devices (*i.e.,* absorbers and WESP) could be operated during periods of startup and shutdown. We found no indication that process operations during startup and shutdown would interfere with the ability to operate the relevant control devices according to good engineering practice. Moreover, the commenters provided no technical justification as to why a different operating limit is needed during startup and shutdown.

Regarding the comparison to the Industrial Boiler NESHAP, the operation of boilers and their associated control devices are different than phosphoric acid plants. While boiler control devices do not have to comply with specific operating limits during startup or shutdown, they must meet a work practice that includes firing clean fuels, operating relevant control devices (*e.g.,* absorbers) as expeditiously as possible, and monitoring the applicable operating parameters (*e.g.,* flow rate) to demonstrate that the control devices are being operated properly. The EPA currently is reconsidering the control requirements for industrial boilers during startup and shutdown (80 FR 3090, January 21, 2015). In the proposed action on reconsideration, we pointed out that some of the control devices used for boilers cannot be operated during the full duration of startup and shutdown because of safety concerns and the possibility of control equipment degradation due to fouling and corrosion. The control devices used for phosphoric acid production do not pose these same risks. Likewise, the fact the Portland Cement NESHAP does not require monitoring of kiln temperature during startup and shutdown is not relevant. The Portland Cement NESHAP requires maintaining a kiln temperature as part of the MACT operating limit. The operating limit for the Portland Cement NESHAP does not apply during startup and shutdown because it is not physically possible to maintain a constant temperature during startup and shutdown of a kiln. In contrast, the feasibility of operating the control devices used to control HAP emissions from phosphoric acid manufacturing is not limited by specific process operating conditions. Therefore, it is feasible to operate the devices during startup and shutdown, and we have determined that it is reasonable to do so considering cost, nonair health and environmental impacts, and energy requirements.

c. Definition Of Startup And Shutdown—Comment. Several commenters argued that the EPA's proposed work practice standard for periods of startup and shutdown failed to account for how equipment in the phosphoric acid industry works. In order to comply with the proposed startup and shutdown requirements, the operator must begin operation of any control device(s) being used at the affected source prior to introducing any feed into the affected source and continue operation of the control device(s) through the shutdown period until all feed material has been processed through the affected source. The commenters noted that it is not feasible to process all feed material from a process prior to shutting down most equipment at a facility. For example, the phosphoric acid reactors and beds in the calciners may not be able to process all the feed material in them prior to shutdown and there would always still be feed material left in the equipment even after it is shutdown. The same would be true for nearly all process units in the industry. The commenters requested that the EPA revise 40 CFR 63.602(h) to require compliance with the work practice standard only up to the point in time when no more feed or in-process materials are being introduced into the production unit.

Two commenters agreed with other commenters that it is not feasible to base the conclusion of a ''shutdown'' on the point at which all feed has ''been processed.'' Instead, they suggested that the EPA should clarify the work practice standard of keeping all emission control equipment active during shutdowns. The commenters reported that facilities in the industry consider the commencement of ''shutdown'' as the moment at which the plant ceases adding feed to the affected process, rather than basing shutdown on when all feed materials have been processed through the process. The commenters recommended that the EPA should define ''shutdown'' to begin when the facility ceases adding feed to an affected process line, and to conclude when the affected process line equipment is deactivated, even though some feed or residues may still be present within particular parts of the process.

One of the commenters also noted that it is common practice to have short-term shutdown of process inputs for temporary maintenance work (including work on emission control equipment) where the entire system is not emptied. In these cases, feed of phosphoric acid and ammonia to the process is suspended as is flow from the reactor to the granulator. The commenter argued that because the source of fluoride to the system has ceased and dust generating material flows are suspended, there should be no significant source of emissions to control, and it is not necessary to require the use of control devices until all feed material has been processed. Instead, the commenter recommended that an affected entity should be allowed to turn off control devices when reactor and granulator feeds have been stopped, unless the system is being emptied, in which case control devices should be required as long as the material handling system is in operation.

Response. We agree with the commenters that the rule needs to have a more precise definition of startup and shutdown that more clearly and reasonably establishes the times when the work practice applies and when the emission limits apply. Accordingly, we added a definition of ''startup'' and ''shutdown'' in the definitions section of the final rule to specify when startup begins and ends, and when shutdown begins and ends.

Based on additional information provided by industry (see ''Email Correspondence Received After Comment Period re Startup Shutdown (May 5, 2015),'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522), we are including a definition of startup in the final rule. The final rule defines startup as commencing when any feed material is first introduced into an affected source and ends when feed material is fully loaded into the affected source. Regarding shutdown, we agree with the commenters that it is not feasible to process all feed material from a process prior to shutting down most equipment at a facility. Such requirement would imply that the control device must be operated after the shutdown ends. The final rule defines shutdown as commencing when the facility ceases adding feed to an affected source and ends when the affected source is deactivated, regardless of whether feed material is present in the affected source. This definition will address concerns about temporary shutdowns as well as shutdowns of longer duration.

In addition, the final rule at 40 CFR 63.602(f) specifies that any control device used at the affected source must be operated during the entire period of startup and shutdown, and must meet the operating limits in Table 4 of the final rule.

4. What is the rationale for our final decisions for the SSM provisions?

For the reasons provided above and in the preamble for the proposed rule, we are finalizing the proposed revisions to the General Provisions table (appendix A of NESHAP subpart AA) to change several references related to requirements that apply during periods of SSM. For these same reasons, we are also finalizing the addition of the following proposed provisions to NESHAP subpart AA: (1) Work practice standards for periods of startup and shutdown in lieu of numeric emission limits; (2) the general duty to minimize emissions at all times; (3) performance testing conditions requirements; (4) site-specific monitoring plan requirements; and (5) malfunction recordkeeping and reporting requirements.

F. Other Changes Made to the Phosphoric Acid Manufacturing NESHAP and NSPS

1. What other changes did we propose for the Phosphoric Acid Manufacturing NESHAP and NSPS?

a. Clarifications to Applicability and Certain Definitions—i. NESHAP Subpart AA. As stated in the preamble to the proposed rule, to ensure the emission standards reflect inclusion of HAP emissions from all sources in the source category, we proposed to amend the definitions of WPPA process line, SPA process line, and PPA process line to include relevant emission points, including clarifiers and defluorination systems at WPPA process lines, and oxidation reactors at SPA production lines. We also proposed removing text from the applicability section that is duplicative of the revised definitions.

We also proposed revising the term ''gypsum stack'' to ''gypsum dewatering stack'' in order to help clarify the meaning of this fugitive emission source, and to alleviate any potential misconception that the ''stack'' is a point source. Other changes we proposed included the addition of definitions for ''cooling pond,'' ''phosphoric acid defluorination process,'' ''process line,'' and ''raffinate stream.''

ii. NSPS Subpart T. As stated in the preamble to the proposed rule, to ensure the emission standards we proposed reflected inclusion of total fluoride emissions from all sources in the defined source category, we proposed to amend the definition of WPPA plant to include relevant emission points, including clarifiers and defluorination systems. We also proposed to remove text from the applicability section that is duplicative of the revised definitions.

iii. NSPS Subpart U. To ensure the emission standards we proposed reflected inclusion of total fluoride emissions from all sources in the defined source category, we proposed to amend the definition of SPA plant to include relevant emission points, including oxidation reactors. We also proposed to remove text from the applicability section that is duplicative of the revised definitions.

b. Testing, Monitoring, Recordkeeping and Reporting —i. NESHAP Subpart AA. As stated in the preamble to the proposed rule, to provide flexibility, we proposed several monitoring options, including pressure and temperature measurements, as alternatives to monitoring of absorber differential pressure. We also proposed monitoring the absorber inlet gas flow rate along with the influent absorber liquid flow rate (and determining liquid-to-gas ratio) in lieu of monitoring only the absorber inlet liquid flow rate.

In addition, we proposed removing the requirement that facilities may not implement new operating parameter ranges until the Administrator has approved them, or 30 days have passed since submission of the performance test results. We proposed that facilities must immediately comply with new operating ranges when they are developed and submitted; and new operating ranges must be established using the most recent performance test conducted by a facility, which allows for changes in control device operation to be appropriately reflected.

As stated in the preamble to the proposed rule, we modified the language for the conditions under which testing must be conducted to require that testing be conducted at ''maximum representative operating conditions'' for the process.[9]

In keeping with the general provisions for CMS (including CEMS and continuous parameter monitoring system (CPMS)), we proposed the addition of a site-specific monitoring plan and calibration requirements for CMS. Provisions were also proposed that included electronic reporting of stack test data. We also proposed modifying the format of NESHAP subpart AA to reference tables for emissions limits and monitoring requirements.

Finally, we proposed HF standards in NESHAP subpart AA by translating the current total fluoride limits (lb total F/ton P_2O_5 feed) into HF limits (lb HF/ton P_2O_5 feed). To comply with HF standards, we proposed that facilities use EPA Method 320.

ii. NSPS Subpart T. We proposed new monitoring and recordkeeping requirements for any WPPA plant that commences construction, modification, or reconstruction after November 7, 2014 to ensure continuous compliance with the standard. As stated in the preamble to the proposed rule, to ensure that the process scrubbing system is properly maintained over time; ensure continuous compliance with standards; and improve data accessibility, we proposed the owner or operator establish an allowable range for the pressure drop through the process scrubbing system. We also proposed that the owner or operator keep records of the daily average pressure drop through the process scrubbing system, and keep records of deviations.

For consistency with terminology used in the associated NESHAP subpart AA, we proposed changing the term ''process scrubbing system'' to ''absorber'' in NSPS subpart T.

iii. NSPS Subpart U. We proposed new monitoring and recordkeeping requirements for any SPA plant that commences construction, modification or reconstruction after November 7, 2014 to ensure continuous compliance with the standard. As stated in the preamble to the proposed rule, to ensure that the process scrubbing system is properly maintained over time; ensure continuous compliance with standards; and improve data accessibility, we proposed the owner or operator establish an allowable range for the pressure drop through the process scrubbing system. We also proposed that the owner or operator keep records of the daily average pressure drop through the process scrubbing system, and keep records of deviations.

For consistency with terminology used in the associated NESHAP subpart AA, we proposed changing the term ''process scrubbing system'' to ''absorber'' in NSPS subpart U.

2. How did the provisions regarding these other proposed changes to the Phosphoric Acid Manufacturing NESHAP and NSPS change since proposal?

a. Clarifications to Applicability and Certain Definitions—i. NESHAP Subpart AA. In consideration of comments received during the public comment period for the proposed rulemaking, we are adopting the proposed clarifications for oxidation reactors as discussed in section V.F.3.a.i of this preamble; however, we are also revising the definition of oxidation reactor in the final rule to clarify that oxidizing agents may include: Nitric acid, ammonium nitrate, or potassium permanganate. Also, in consideration of comments received (see section V.F.3.a.ii of this preamble for details), we are not adopting the proposed clarifications for defluorination systems and clarifiers.

We have not made any change to the proposed revision to rename ''gypsum stack'' to ''gypsum dewatering stack.'' We have also not made any changes to the proposed definitions for ''cooling pond'' and ''raffinate stream''; however, we are removing the proposed definitions for ''phosphoric acid defluorination process'' and ''process line'' for reasons discussed in sections V.F.3.a.ii and V.F.3.a.iii of this preamble, respectively.

Finally, we are removing the proposed language ''includes, but is not limited to'' in the definitions of WPPA, SPA, and PPA process lines for reasons discussed in section V.F.3.a.iv of this preamble.

ii. NSPS Subpart T. In consideration of comments received (see section V.F.3.a.ii of this preamble for details), we are not adopting the proposed clarifications for defluorination systems and clarifiers. We are also removing the proposed language ''includes, but is not limited to'' in the definitions of WPPA plant for reasons discussed in section V.F.3.a.iv of this preamble.

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[9] Based on the EPA memorandum, ''Issuance of the Clean Air Act National Stack Testing Guidance,'' dated April 27, 2009.

iii. NSPS Subpart U. In consideration of comments received during the public comment period for the proposed rulemaking, we are adopting the proposed clarifications for oxidation reactors as discussed in section V.F.3.a.i of this preamble; however, we are also revising the proposed definition of oxidation reactor in the final rule to clarify that oxidizing agents may include: Nitric acid, ammonium nitrate, or potassium permanganate. We are also removing the proposed language ''includes, but is not limited to'' in the definitions of SPA plant for reasons discussed in section V.F.3.a.iv of this preamble.

b. Testing, Monitoring, Recordkeeping and Reporting—i. NESHAP Subpart AA. We have not made any changes in our proposed determination that pressure drop is not an appropriate monitoring parameter for absorbers that are designed to operate with pressure drops of 5 inches of water column or less. However, in consideration of comments received during the public comment period for the proposed rulemaking, we are not adopting the proposed options to monitor: (1) The temperature at the wet scrubber gas stream outlet and pressure at the liquid inlet of the absorber, or (2) the temperature at the scrubber gas stream outlet and scrubber gas stream inlet. Instead, we have revised Table 3 of NESHAP subpart AA to require liquid-to-gas ratio monitoring for low-energy absorbers, and influent liquid flow and pressure drop monitoring for high-energy absorbers; and we are keeping liquid-to-gas ratio monitoring as an option for high-energy absorbers in the final rule. (See section V.F.3.b.i and V.F.3.b.ii of this preamble for details.)

In addition to these revisions, we are making corrections at 40 CFR 63.607(a) to clarify the procedures for establishing a new operating limit based on the most recent performance test. We are also revising the requirements at 40 CFR 63.605(d)(1)(ii)(B) of the final rule to remove the requirement that facilities must request and obtain approval of the Administrator for changing operating limits. (See section V.F.3.b.iii and V.F.3.b.iv of this preamble for details.)

Also, for reasons discussed in the in the Comment Summary and Response document available in the docket, we are revising the annual testing schedule in the final rule at 40 CFR 63.606(b), and the terminology for ''maximum representative operating conditions'' in the final rule at 40 CFR 63.606(d).

We are not making any changes to the proposed addition of a site-specific monitoring plan and calibration requirements for CMS. We are also keeping the proposed term ''absorber'' in lieu of ''scrubber,'' as well as the proposed format of NESHAP subpart AA to reference tables for emissions limits and monitoring requirements.

Lastly, we are retaining the current total fluoride limits and not adopting the proposed HF standards and associated EPA Method 320 testing in NESHAP subpart AA (see section V.F.3.c of this preamble for details).

ii. NSPS Subpart T. We are not making changes to the proposed monitoring and recordkeeping requirements for any WPPA plant that commences construction, modification or reconstruction after August 19, 2015 to ensure continuous compliance with the standard. We are also keeping the proposed term ''absorber'' in lieu of ''process scrubbing system.''

iii. NSPS Subpart U. We are not making changes to the proposed monitoring and recordkeeping requirements for any SPA plant that commences construction, modification, or reconstruction after August 19, 2015 to ensure continuous compliance with the standard. We are also keeping the proposed term ''absorber'' in lieu of ''process scrubbing system.''

3. What key comments did we receive on the other changes to the Phosphoric Acid Manufacturing NESHAP and NSPS, and what are our responses?

Several comments were received regarding the proposed clarifications to applicability and certain definitions, revisions to testing, monitoring, recordkeeping and reporting, translation of total fluoride to HF emission limits, and revisions to other provisions for the Phosphoric Acid Manufacturing source category. The following is a summary of significant comments and our response to those comments. Other comments received and our responses to those comments can be found in the Comment Summary and Response document available in the docket for this action (EPA–HQ–OAR–2012–0522).

a. Applicability Clarifications and Certain Definitions—i. Oxidation Reactors—Comment. Several commenters remarked that the proposed definition of SPA process line to include oxidation reactors is problematic and goes beyond clarification. These commenters requested that the EPA develop more specific language or provide a clear technical basis under the CAA because any equipment that was not expressly included in EPA's MACT floor calculations should not be included in the affected source definition.

Commenters mentioned that the EPA's memorandum ''Applicability Clarifications to the Phosphoric Acid Manufacturing Source Category,'' which is available in the docket for this action, captured four facilities, but it was not clear whether the PCS Aurora facility was included in the count. These commenters stated that the oxidation step at this facility is carried out in agitated tanks that do not have any emissions control, and the emissions from the oxidation step are not included in their annual performance testing (when demonstrating compliance with the current total fluoride limits). The commenters said that it was not clear whether this oxidation step involves an ''oxidation reactor'' as proposed; and, if it does, the commenters argued that the EPA has not considered additional costs imposed by including ''any equipment that uses an oxidizing agent to treat phosphoric acid'' within the scope of the NESHAP at 40 CFR part 63, subpart AA.

Response. We are adopting the proposed SPA process line definition in NESHAP subpart AA, and the proposed SPA plant definition in NSPS subpart U, to include oxidation reactors. Based on information in process flow diagrams provided by facilities, we initially believed that oxidation reactors were part of the SPA process lines that would have been considered in the original MACT analysis, and, thus subject to the existing limits. In response to comments that stated the opposite was true, we searched historical data, specifically the 1996 memorandum ''National Emission Standards for Hazardous Air Pollutants from Phosphoric Acid Manufacturing and Phosphate Fertilizers Production; Proposed Rules—Draft Technical Support Document and Additional Technical Information'' (1996 TSD). The 1996 TSD lists, in Attachment 2, the test data for SPA process lines that were assembled for the MACT floor analysis (the 1996 TSD is item II–B–20 in Docket A–94–02). Based on this review as well as a facility construction air permit, we determined that oxidation reactor emissions from at least one facility, PCS White Springs (see the emission point ''Occidental, Suwanee Rv., FL–G'' in the 1996 TSD), were included with this assembled SPA test dataset. It is possible that three other facilities (see the emission points ''J.R. Simplot, Pocatello, ID'' for the Simplot Don-Pocatello facility, ''Nu-West, Soda Springs, ID'' for the Agrium Nu-West facility, and ''Texasgulf, Aurora, NC'' for the PCS Aurora facility in the 1996 TSD) with oxidation reactors were also included in this original dataset since we know today that these facilities have oxidation reactors; however, it is unclear whether the oxidation reactors at these facilities were operating when the dataset was assembled. Nevertheless, based on the emission point ''Occidental, Suwanee Rv., FL–G,'' SPA process lines that incorporate an oxidation reactor were included as part of the SPA emissions dataset that was evaluated in order to conduct the MACT floor analysis.

In addition, the EPA's technology review revealed that SPA process lines at four different facilities include an oxidation reactor to remove organic impurities from the acid. We determined that one of these facilities (Simplot Don-Pocatello) already ducts their oxidation reactor emissions through their SPA process line wet scrubber, and is achieving compliance with the SPA total fluoride emission limit. For two of these facilities (PCS White Springs and Agrium Nu-West), we determined that when their oxidation reactor emissions are combined with the rest of their SPA process line emissions, the facilities are in compliance with the total fluoride emission limit. Therefore, for these three facilities it would not be necessary to upgrade existing control systems, or to install a control system, in order to comply with the rule.

With regard to the oxidation reactor at the fourth facility (PCS Aurora), the Agency has determined that this process (*i.e.,* an oxidation step carried out in agitated tanks) does qualify as an oxidation reactor. Based on information that we received from industry after the public comment period ended for the proposal (see docket item EPA–HQ–OAR–2012–0522–0051), potassium permanganate is used in the PCS Aurora oxidation step. This oxidizing agent was one of three specifically cited in our memorandum ''Applicability Clarifications to the Phosphoric Acid Manufacturing Source Category,'' which is available in the docket for this action, so based on the data available, this oxidation step should be included as part of the SPA process line emissions when determining compliance with the SPA total fluoride emission limit. Furthermore, based on this same information that we received from industry after the public comment period ended for the proposal, PCS Aurora may need to install a new absorber in order to control its oxidation process emissions due to logistical complications and concerns about inadequate capacity of other existing absorbers at their SPA units. PCS Aurora estimated the absorber (venturi scrubber) would incur capital costs of approximately $270,500, based on prior absorber purchases for its facility. We estimated annual costs of approximately $95,000. The costs associated with this change are discussed further in the memorandum ''Control Costs and Emissions Reductions for Phosphoric Acid and Phosphate Fertilizer Production Source Categories—Final Rule,'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522.

The definition of oxidation reactor in the final rule for NESHAP subpart AA has been revised to clarify that oxidizing agents may include: Nitric acid, ammonium nitrate, or potassium permanganate. The words ''or step'' has also been added to the definition of oxidation reactor, for instances when a facility may not typically identify their oxidation process as occurring in a reactor. The definition now states that ''oxidation reactor means any equipment or step that uses an oxidizing agent (*e.g.,* nitric acid, ammonium nitrate, or potassium permanganate) to treat SPA.'' Similarly, the definition of ''SPA plant'' in the final rule for NSPS subpart U has also been revised to reflect these changes.

ii. Defluorination and Clarifiers— Comment. Many commenters opposed the proposed expanded definition of ''wet-process phosphoric acid line'' to include ''clarifiers'' and ''defluorination processes.'' These commenters stated that the proposed revisions have the potential to pull in several ''defluorination processes'' and ''clarifiers'' that are not subject to the current rule (*e.g.,* animal feed phosphate production operations that have traditionally been outside the scope of this subpart). These commenters argued that any unit operation that conducts evaporation or concentrates phosphoric acid will have the effect of defluorinating to some extent. One of these commenters stated that they have a desulfation process at one of their facilities that reduces F; the commenter also said that this facility's WPPA process line has several filter product tanks, evaporator feed tanks, and evaporator product tanks that could potentially be deemed clarifiers, and thus be pulled into the proposed rule. Another of these commenters argued that it is not logical to include clarifier and defluorination systems in the definition because they operate independently of process lines, and are often operated when feed is not put into process lines (and so are not a process line manufacturing phosphoric acid by reacting phosphate rock and acid). This commenter added that clarifiers often operate more like tanks than process equipment and are not routinely emptied; and emissions from clarifiers are not a function of phosphate feed material to the reactor. The commenter stated that the addition of clarifiers will require significant facility modifications to accommodate emissions testing because although some clarifiers are evacuated to WPPA scrubbers, others are not; and even though some clarifiers have independent evacuation and scrubbing systems, other clarifiers have no evacuation and scrubbing systems. Another commenter also stated that one of their facilities contains clarifiers that are not source tested or vented to a wet scrubber. This commenter stated that it was not possible for one of their facilities to determine whether they meet the proposed standard for a WPPA process line that includes defluorination processes because their defluorination units are not only integrated with their WPPA process, but also with processes that do not meet the definition of WPPA lines. A commenter added that defluorination processes and clarifiers are often subject to separate emissions control requirements in their title V permits.

Two commenters stated that since the original rule was adopted, the definition of ''wet-process phosphoric line'' has not been interpreted to extend or apply to clarifiers or defluorination processes. One of these commenters claimed that the only rationale the EPA provides is that the rules were ''initially intended'' to cover these sources, but argued that neither the original proposal, nor the original final rule mentioned the term ''clarifier'' or ''defluorination process.'' The commenters requested that the EPA conduct CAA section 112(d)(2) or 112(d)(3) analyses for these new affected units. If the EPA conducts these analyses, and decides to expand the definition of ''wet-process phosphoric acid line'' to include ''clarifiers'' and ''defluorination processes,'' a commenter suggested that the definition exclude units that partially clarify or defluorinate an in-process stream incidentally.

Response. Based on information in process flow diagrams provided by facilities, we initially believed that clarifiers and defluorination systems were part of the WPPA process lines that would have been considered in the original MACT analysis, and, thus, subject to the existing limits. However, the EPA agrees that clarifiers and defluorination systems should not be included in the WPPA process line definition of NESHAP subpart AA, based on the new information available. We also agree that clarifiers and defluorination systems should not be included in the WPPA plant definition of NSPS subpart T.

In the proposed rules, the EPA was specifically referring to defluorination processes that use diatomaceous earth and are included as part of the WPPA process line; however, commenters explained that this type of process is used solely in animal feed production. Because defluorination processes that use diatomaceous earth are not related to phosphoric acid manufacturing, as we first surmised, it is not appropriate to include defluorination processes in the WPPA process line definition.

In response to comments regarding the inclusion of clarifiers in the WPPA process line definition, we searched historical data. Specifically, we reviewed the 1996 memorandum ''National Emission Standards for Hazardous Air Pollutants from Phosphoric Acid Manufacturing and Phosphate Fertilizers Production; Proposed Rules—Draft Technical Support Document and Additional Technical Information'' (1996 TSD) to determine if clarifier emissions were included in the MACT floor evaluation for WPPA process lines (the 1996 TSD is item II–B–20 in Docket A–94–02). The 1996 TSD lists, in Attachment 2, the WPPA test data that were assembled for the MACT floor analysis. Based on this review, we were not able to confirm that clarifiers were included as part of the WPPA emissions dataset that was evaluated in order to conduct the MACT floor analysis; therefore, we are not including clarifiers in the WPPA process line definition. Similarly, we are not including clarifiers in the WPPA plant definition of NSPS subpart T.

iii. Generic Process Line Definition—Comment. One commenter stated that the EPA has introduced ambiguity and vagueness with its definition of a generic ''process line'' that includes ''all equipment associated with the production of any grade or purity of a phosphoric acid product including emission control equipment.'' The commenter asserted that under this expansive definition, every hypothetical fugitive emission source would have to be accounted for in determining compliance. The commenter explained that the EPA has not collected emission data from ''all equipment'' nor provided guidance on estimating emissions for such sources in order to allow entities with process lines to demonstrate compliance. The commenter stressed the ''process line'' definition, as it currently stands, could include a wash plant that prepares phosphate ore or product storage tanks due to these sources being considered ''associated'' with production and thus subject to the proposed NESHAP.

Response. The Agency agrees with the commenter that it is not necessary to include the generic ''process line'' definition, and has removed it from the NESHAP subpart AA final rule. This definition did not provide additional clarity to facilities, and it was not our intent to include emissions from ''all equipment'' that is ''associated'' with phosphoric acid production for compliance determinations. Specific definitions are provided for WPPA process line, SPA process line, and PPA process line and, therefore, enough specificity is already provided in the rule.

iv. ''Includes, but is Not Limited to''—Comment. A commenter remarked that incorporating the language ''includes, but is not limited to'' in the definitions of WPPA, SPA, and PPA process lines is overly broad and creates ambiguity. They stated that industry should have certainty as to the applicability and scope of the rule, but the language ''includes, but is not limited to'' creates uncertainty as to where the affected equipment begins and ends for purposes of demonstrating compliance.

Response. We agree that this language creates overly broad process line definitions and can lead to regulatory uncertainty for affected sources. Therefore, we are not finalizing the language ''includes, but is not limited to'' in the definitions of WPPA, SPA, and PPA process lines of NESHAP subpart AA. Similarly, we are not finalizing the language ''includes, but is not limited to'' in the definitions of WPPA plant and SPA plant of NSPS subpart T and NSPS subpart U, respectively.

b. Testing, Monitoring, Recordkeeping and Reporting—i. Pressure Drop Across Absorber—Comment. Several commenters requested the EPA delete the requirement that pressure drop across an absorber must be greater than 5 inches of water in order to use the option of measuring pressure drop as an operating parameter. These commenters contended that the EPA has not articulated any basis for the requirement. These commenters provided data demonstrating that units operate in compliance with the emission standards when the pressure drop across an absorber is less than 5 inches of water. One of these commenters expressed safety concerns associated with operating scrubbers at higher range pressure drop settings, citing one of its facilities that experienced the entrainment of moisture within the absorbing tower when operating at pressure drops in excess of 8 inches of water, and another that experienced the buildup of excessive fumes on the digester floor when operating the digester scrubber as high as 6 inches of water.

Response. The Agency maintains its determination that pressure drop is not an appropriate monitoring parameter for absorbers that do not use the energy from the inlet gas to increase contact between the gas and liquid in the absorber (see ''Use of Pressure Drop as an Operating Parameter,'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522). Therefore, we are not revising this proposed amendment.

High-energy (*i.e.,* high pressure drop) absorbers, such as venturi scrubbers, are designed to use the energy in the inlet gas to atomize the liquid stream entering the absorber which increases the contact between the liquid droplets and gas. For these types of absorbers, pressure drop is an appropriate monitoring parameter because changes in pressure drop values indicate that either liquid droplets are not being formed effectively inside the absorber (falling pressure drop), or that the absorber is fouled (increasing pressured drop). Pressure drop is not an appropriate monitoring parameter for low-energy absorbers (*i.e.,* absorbers that are designed to operate with pressure drops of 5 inches of water column or less) because pressure drop is not integral to the mechanism used in the absorber to mix the scrubbing liquid and inlet gas. Furthermore, in a meeting that occurred after the public comment period closed (see ''EPA Meeting Minutes for TFI Discussion March 12, 2015,'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522), industry stated that there is no correlation between pressure drop and absorber performance.

With regard to the safety concerns raised by one commenter when operating low-energy absorbers at high pressure drop settings, the proposed rule (NESHAP subpart AA) did not require low-energy absorbers (*i.e.,* absorbers that are designed to operate with pressure drops of 5 inches of water column or less) to operate at pressure drops greater than 5 inches of water column. Instead, the proposed rule required a different parameter to be monitored for these types of absorbers. Nevertheless, based on other comments received, we are not adopting the proposed monitoring for low-energy absorbers, and have revised the final rule (NESHAP subpart AA) to require liquid-to-gas ratio monitoring for low-energy absorbers in lieu of monitoring influent liquid flow and pressure drop through the absorber (see section V.F.3.b.ii of this preamble for further details).

ii. Absorber Monitoring Options—Comment. Several commenters called attention to the options of either measuring: (1) The temperature at the wet scrubber gas stream outlet and pressure at the liquid inlet of the absorber, or (2) the temperature at the scrubber gas stream outlet and scrubber gas stream inlet. One of these commenters said that they do not believe monitoring gas temperature in locations of large ambient temperature ranges would provide accurate monitoring of the absorbers performance. The commenter argued that temperature and pressure probes would be very susceptible to scaling issues. In addition, this commenter contended that liquid inlet pressure does not provide any additional monitoring of the absorber performance, since the inlet liquid flow rate is already measured and monitored. Another commenter contended that the EPA has not provided any data or analysis to show that there is a correlation between temperature and emissions; the commenter stated that they were not aware of any data suggesting a relationship between exit temperature and emissions, or that monitoring temperature difference across an absorber would be effective. One of these commenters argued that they were not in a position to evaluate the difficulties associated with performing the associated monitoring and establishing the requisite operating ranges.

Response. Absorber outlet gas temperature is often used to indicate a change in operation for absorbers that are used to control thermal processes. Because this source category uses the wet process in lieu of a thermal process to produce phosphoric acid, the Agency agrees with the commenters that temperature is not an appropriate monitoring parameter for absorbers used in this source category, and has removed these monitoring options from Table 3 of the final rule (NESHAP subpart AA). However, in light of this comment, the Agency has revised Table 3 of NESHAP subpart AA to require liquid-to-gas ratio monitoring for low-energy absorbers (*i.e.,* absorbers that are designed to operate with pressure drops of 5 inches of water column or less) in lieu of monitoring influent liquid flow and pressure drop through the absorber. (See section V.F.3.b.i of this preamble for further details of why we are not allowing pressure drop monitoring for low-energy absorbers.) Although liquid flow to the absorber is the most critical parameter for monitoring absorption systems, monitoring the inlet gas flow rate along with the influent liquid flow rate (and determining liquid-to-gas ratio) provides better indication of whether enough water is present to provide adequate scrubbing for the amount of gas flowing through the system. Furthermore, the Agency has revised Table 3 of NESHAP subpart AA to require influent liquid flow and pressure drop monitoring for high-energy (*i.e.,* high pressure drop) absorbers, such as venturi scrubbers; and we are keeping liquid-to-gas ratio monitoring as an option for high-energy absorbers in the final rule. Rather than calculating one minimum flow rate at maximum operating conditions that must be continuously adhered to, this alternative provision (*i.e.,* liquid-to-gas ratio monitoring for high-energy absorbers) allows a facility to optimize the liquid flow for varying gas flow rates. By using a liquid-to-gas ratio, sources may save resources by reducing the liquid rate with reductions in gas flow due to periods of lower production rates.

The Agency believes the cost to implement these finalized monitoring requirements is minimal for facilities. For low-energy absorbers, we are allowing the gas stream to be measured by either measuring the gas stream flow at the absorber inlet or using the design blower capacity, with appropriate adjustments for pressure drop. Therefore, facilities would not need to purchase new equipment to measure gas flow at the inlet of the absorber since they may choose to use design blower capacity. Furthermore, we are not requiring any new monitoring for high-energy absorbers; therefore, these facilities are already equipped to monitor as required in the final rule.

iii. Operating Range Established From a Previous Test—Comment. One commenter stated that 40 CFR 63.607(a) is somewhat ambiguous, tending to suggest that affected facilities would be immediately required to implement new equipment operating ranges following a source test, even if operating conditions from previous source tests demonstrated compliance with fluoride emission standards. The commenter argued that there is no reason that a new performance test at a new operating range should invalidate a previous performance test at a different operating range.

Response. The Agency has clarified in the final rule at 40 CFR 63.607(a) that during the most recent performance test, if owners or operators demonstrate compliance with the emission limit while operating their control device outside the previously established operating limit, then limits must be established. Owners or operators must establish a new operating limit based on that most recent performance test and notify the Administrator that the operating limit changed based on data collected during the most recent performance test. Public comments on the 1999 rule stated that the equipment and control devices in these source categories are subject to harsh conditions that cause corrosion and scaling of the process components. Accordingly, the performance of the emissions controls will vary over time, and so might emissions. Thus, the Agency disagrees with the commenter's argument. We have determined that a new performance test conducted under a particular operating range should invalidate a previous operating range that was established under different operating conditions. An operating limit (*e.g.,* an operating range, a minimum operating level, or maximum operating level) is established using the most recent performance test, or in certain instances, a series of tests (potentially including historical tests). However, in all cases, if owners or operators demonstrate compliance with an emission limit during the most recent performance test, and during this performance test an owner's or operator's control device was operating outside the previously established operating limit, the owner or operator must establish a new operating limit that incorporates that most recent performance test.

iv. Approving Operating Ranges—Comment. Several commenters support the EPA's proposal to eliminate the requirement that facilities may not implement new operating parameter ranges until the Administrator has approved them, or 30 days have passed since submission of the performance test results. A commenter pointed out that 40 CFR 63.605(d)(1)(iii)(B), as proposed, does not provide the 30-day default period for the effectiveness of the new ranges if the EPA Administrator does not act; therefore, as currently set forth in the proposed rule, sources will be left in limbo waiting for the EPA Administrator to respond before they can implement new ranges. A commenter suggested that the EPA revise the proposed regulatory language to require submission of the new ranges to EPA, but delete the requirement to request and obtain EPA's approval of the new ranges. Similarly, another commenter requested the EPA clarify the process for establishing new equipment operating ranges following source performance testing. This commenter contended that facilities should have the ability to update operating parameters if they desire based on source testing, and the facility should be required to submit the new ranges, but not be required to obtain EPA's approval of the new ranges.

In addition, a commenter requested that the EPA clarify how revising the proposed regulatory language to require submission of the new ranges to the EPA, but deleting the requirement to request and obtain EPA's approval of the new ranges, will affect possible obligations to undertake permit modifications of title V permits under 40 CFR part 70. This commenter stated that such administrative processes are not fully anticipated in the proposed rule.

Response. In the proposed NESHAP subpart AA, the Agency intended that facilities not be required to obtain approval, and, instead, immediately comply with a new operating limit when it is developed and submitted to the Administrator. Therefore, the requirements at proposed 40 CFR 63.605(d)(1)(iii)(B) have been revised in the final rule at 40 CFR 63.605(d)(1)(ii)(B), as the commenter requests, to remove the requirement that facilities must request and obtain approval of the Administrator for changing operating limits. Furthermore, the Agency suggests that the title V permit be modified as soon as the Administrator is notified of a change in an operating limit. The Agency acknowledges that corrections and modifications to permit applications could become a problem for a facility, particularly if the Administrator determines the operating limit is not appropriate after a facility has already applied for the change to be made in its air permit; however, we expect this scenario to be rare.

c. Translation of Total Fluoride to HF Emission Limits—Comment. With regard to the proposed NESHAP subpart AA, several commenters opposed the use of EPA Method 320 to test for HF, and supported the retention of a total fluoride compliance standard and associated testing using EPA Method 13A or 13B. These commenters argued that EPA Method 320 leads to unreliable and unrepresentative results because some reactive fluoride compounds in the exhaust may form HF in the sampling equipment. The commenters explained that complex reactions leading to fluoride emissions occur not only in the processing units located at the Phosphoric Acid Manufacturing source category, but also in the scrubber systems designed to remove fluoride from the stack gases. Commenters stated that these reactions result in a mix of gaseous, aerosol, and particle bound fluoride (all three phases) in the stack gas, in the form of compounds like silica tetrafluoride, various fluorosilicate aerosols and/or droplets, ammonium fluoride, ammonium bifluoride, and/or ammonium fluorosilicate; and argued that these compounds have the potential to be captured in a Method 320 sampling equipment, biasing or interfering with the results of the sampling. Commenters specified that the EPA Method 320 sampling conducted in response to the EPA's information requests demonstrated that SiF_4 readily reacts with water vapor in the stack gas producing HF and silicon hydroxide; and one of the commenters provided information showing that this reaction is dependent on temperature, moisture, and residence time in the sampling system. Additionally, some of the commenters listed technical issues that they encountered during the EPA Method 320 sampling that they conducted in response to EPA's information requests. These commenters recommended certain procedures be followed when conducting EPA Method 320 at the Phosphoric Acid Manufacturing source category; however, they also cautioned that their recommendations would not resolve all of the inherent problems with the sampling and analysis process. The commenters also expressed concern over the increase in testing costs from using EPA Method 320 instead of EPA Method 13A or 13B, citing an increase of at least 3 to 4 times when using EPA Method 320 instead of EPA Method 13B.

We also received comments regarding the option to use Fourier transform infrared spectroscopy (FTIR) HF CEMS as a continuous monitoring compliance approach for HF at NESHAP subpart BB affected sources. One commenter contended that the EPA must consider requiring continuous HF emission monitoring before finalizing the proposal, and pointed out that there is a HF sensor (suitable for 0–10 part per million (ppm) monitoring range and a 0.1 ppm resolution) available for the Ultima X Series Gas Monitors. Several commenters opposed this option and cited EPA's technical memorandum ''Approach for Hydrogen Fluoride Continuous Emission Monitoring and Compliance Determination with EPA Method 320.'' They argued that the option to use FTIR HF CEMS exceeds the capabilities of existing technology, and that there are no details on the required methods to implement such a system or known field demonstrations of this type of system, and that the option has not been proven.

Finally, one commenter requested the EPA explain its technical basis for abandoning the longstanding total fluoride surrogate for HF. The commenter argued that the EPA has established similar surrogacy relationships to measure HAP in other regulated source categories in the past.

Response. In response to the January 2014 CAA section 114 request, processes at the Phosphoric Acid Manufacturing source category were tested for HF using EPA Method 320. Based on those results, the Agency concluded that moving to a form of the standard that requires HF (the target HAP) to be measured (but retaining the same numeric values as the current total fluoride standards) would be achievable by all facilities. However, in light of information provided by commenters, the Agency has re-evaluated the proposed revision to the standard and determined that EPA Method 320 is not an appropriate test method for accurately measuring HF emissions from process lines in this specific source category due to the complex and often incomplete chemical reactions with silicon compounds in these sources. Accordingly, the Agency is not adopting the proposed HF standards in NESHAP subpart AA. The Agency has determined that SiF_4 and water are naturally present in the exhaust gases of the processes located at the Phosphoric Acid Manufacturing source category; and these chemical compounds will react to form HF and silicon dioxide in the near field from the emission point on release into the atmosphere. The Agency has reviewed a study[10] stating that the equilibrium of this chemical reaction is highly dependent on temperature such that as temperature increases, the conversion of SiF_4 to HF increases. At high sampling temperatures (*i.e.,* sampling temperatures ranged from about 150 to 300 degrees Fahrenheit during the EPA Method 320 testing conducted pursuant to the January 2014 CAA section 114 requests), there is nearly a complete conversion of SiF_4 to HF. Therefore, as SiF_4 is captured in the EPA Method 320 sampling system, it may react with moisture (water) to form HF, resulting in HF measurements from this source category that are biased. That is, due to the chemical interactions and reactions with moisture at different temperatures, some of the HF emissions detected by EPA Method 320 may not represent HF that exists in the exhaust stack or HF released from phosphoric acid production.

As a result of our determination to not adopt the proposed HF standards, the

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[10] Koogler & Associates, Inc. ''Technical Evaluation of the Measurement Limitations Associated with Source HF Emissions by EPA Method 320.'' January 21, 2015.

Agency has retained the current total fluoride limits (lb total F/ton P_2O_5 feed) measured using EPA Method 13A or 13B in NESHAP subpart AA as a surrogate for the HAP HF, rather than HF emission limits using EPA Method 320. Furthermore, in light of this conclusion, the Agency is not finalizing an option to use FTIR HF CEMS. In the final rule promulgated on June 10, 1999 (64 FR 31358), the EPA explained that total fluoride was used as a surrogate for HF to establish MACT for emissions from process sources because no direct measurements of HF were available and because the NSPS are based on total F. On November 7, 2014, we proposed HF emission limits in an attempt to base the standard on the specific HAP (HF) that is emitted by this source category because we concluded that new technology (EPA Method 320) allows for direct measurement of HF, and because it is preferred to measure the listed HAP directly when possible. However, in light of the chemical interactions that may occur at this source category during sample collection using EPA Method 320 (skewing HF testing results), we are retaining the long-standing surrogate of total fluoride for HF and the annual testing with EPA Method 13A or 13B. Results from EPA Method 13A or 13B testing include all fluoride compounds, including HF. Furthermore, since the control of total fluoride and HF from process sources at this source category is accomplished with the same control technology (scrubbers), the total fluoride emission limits will result in installation of the MACT for HF and the same level of HF control will be achieved regardless of how the emission limits are expressed. The use of total fluoride as a surrogate for HF simply changes the metric for compliance demonstration, not the actual level of emission control achieved. As such, we are retaining the existing total fluoride limits for all emission sources in NESHAP subpart AA. Although, at present time, the Agency is not finalizing HF standards in NESHAP subpart AA, it may be possible to do so in a future rulemaking with additional data and specificity on monitoring requirements.

4. What is the rationale for our final decisions regarding these other changes to the Phosphoric Acid Manufacturing NESHAP and NSPS?

For the reasons provided above and in the preamble for the proposed rule, we are finalizing: The proposed requirement in NESHAP subpart AA that pressure drop across an absorber must be greater than 5 inches of water in order to use the option of measuring pressure drop as an operating parameter; the proposed definitions for ‘‘superphosphoric acid process line’’ (in NESHAP subpart AA) and ‘‘superphosphoric acid plant’’ (in NSPS subpart U) to include oxidation reactors; and other proposed clarifications and corrections.

Additionally, for the reasons provided above, we are making the revisions, clarifications and corrections noted in section V.F.2 in the final rules for NESHAP subpart AA, NSPS subpart T, and NSPS subpart U.

VI. What is the rationale for our final decisions and amendments for the Phosphate Fertilizer Production source category?

For each issue related to the Phosphate Fertilizer Production source category, this section provides a description of what we proposed and what we are finalizing for the issue, the EPA's rationale for the final decisions, and amendments and a summary of key comments and responses. For all comments not discussed in this preamble, comment summaries and the EPA's responses can be found in the Comment Summary and Response document available in the docket.

A. Residual Risk Review for the Phosphate Fertilizer Production Source Category

1. What did we propose pursuant to CAA section 112(f) for the Phosphate Fertilizer Production source category?

Pursuant to CAA section 112(f), we conducted a residual risk review and presented the results of this review, along with our proposed decisions regarding risk acceptability and ample margin of safety, in the November 7, 2014, proposed rule for the Phosphate Fertilizer Production NESHAP (79 FR 66512). The results of the risk assessment are presented briefly below in Table 4 of this preamble, and in more detail in the residual risk document, ‘‘Residual Risk Assessment for Phosphate Fertilizer Production and Phosphate Fertilizer Production Source Categories in support of the July 2015 Risk and Technology Review Final Rule,'' which is available in the docket for this rulemaking.

TABLE 4—HUMAN HEALTH RISK ASSESSMENT FOR PHOSPHATE FERTILIZER PRODUCTION

Category & number of facilities modeled	Cancer MIR (in 1 million)		Cancer incidence (cases per year)	Population with risks of 1-in-1 million or more	Population with risks of 10-in-1 million or more	Max chronic non-cancer HI		Worst-case max acute non-cancer HQ
	Based on actual emissions	Based on allowable emissions				Based on actual emissions	Based on allowable emissions	
Phosphate Fertilizer ..... (11 facilities)	0.5	0.5	0.001	0	0	0.003	0.003	HQ_{REL} = 0.4 (elemental Hg) HQ_{AEGL-1} = 0.09 (hydrofluoric acid).
Facility-wide (11 facilities).	0.5	....	0.001	0	0	0.2		

Based on actual emissions for the Phosphate Fertilizer Production source category, the MIR was estimated to be less than 1-in-1 million, the maximum chronic non-cancer TOSHI value was estimated to be up to 0.003, and the maximum off-site acute HQ value was estimated to be up to 0.4. The total estimated national cancer incidence from this source category, based on actual emission levels, was 0.001 excess cancer cases per year, or one case in every 1,000 years. Based on MACT-allowable emissions for the Phosphate Fertilizer Production source category, the MIR was estimated to be less than 1-in-1 million, and the maximum chronic non-cancer TOSHI value was estimated to be up to 0.003. We also found there were emissions of several PB–HAP with an available RTR multipathway screening value, and, with the exception of Hg compounds, the reported emissions of these HAP (*i.e.,* lead compounds, and cadmium compounds) were below the multipathway screening value for each compound. One facility emitted divalent Hg (Hg^{2+}) above the Tier I screening threshold level, exceeding the screening threshold by a factor of 20. Consequently, we conducted a Tier II screening assessment for Hg^{2+}. This assessment uses the assumption that the biological productivity limitation of each lake is 1 gram of fish per acre of water, meaning that in order to fulfill the adult ingestion rate, a fisher would need to fish from 373 total acres of lakes. The result of this analysis was the development of a site-specific emission screening threshold for Hg^{2+}. We compared this Tier II screening threshold for Hg^{2+} to the facility's Hg^{2+} emissions. The facility's emissions exceeded the Tier II screening threshold by a factor of 3.

Additionally, to refine our Hg Tier II Screen for this facility, we first examined the set of lakes from which the angler ingested fish. Any lakes that appeared to not be fishable or publicly accessible were removed from the assessment, and the screening assessment was repeated. After we made the determination the three critical lakes were fishable, we analyzed the hourly meteorology data from which the Tier II meteorology statistics were derived. Using buoyancy and momentum equations from literature, and assumptions about facility fenceline boundaries, we estimated by hour the height achieved by the emission plume before it moved laterally beyond the assumed fenceline. If the plume height was above the mixing height, we assumed there was no chemical exposure for that hour. The cumulative loss of chemical being released above the mixing height reduces the exposure and decreases the Tier II screening quotient. Although the refined Tier II analysis for Hg emissions indicated a 23-percent loss of emissions above the mixing layer due to plume rise, this reduction still resulted in an angler screening non-cancer value equal to 2.

For this facility, after we performed the lake and plume rise analyses, we reran the relevant Tier II screening scenarios for the travelling subsistence angler in TRIM.FaTE with the same hourly meteorology data and hourly plume-rise adjustments from which the Tier II meteorology statistics were derived. The use of the time-series meteorology reduced the screening value further to a value of 0.6. For this source category our analysis indicated no potential for multipathway impacts of concern from this facility. The maximum facility-wide MIR was less than or equal to 1-in-1 million and the maximum facility-wide TOSHI was 0.2. We weighed all health risk factors in our risk acceptability determination, and we proposed that the residual risks from the Phosphate Fertilizer Production source category are acceptable.

We then considered whether the Phosphate Fertilizer Production NESHAP provides an ample margin of safety to protect public health and prevents, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect. In considering whether the standards should be tightened to provide an ample margin of safety to protect public health, we considered the same risk factors that we considered for our acceptability determination and also considered the costs, technological feasibility and other relevant factors related to emissions control options that might reduce risk associated with emissions from the source category. We proposed that the current standards provided an ample margin of safety to protect public health. With respect to adverse environmental effects, none of the individual modeled concentrations for any facility in the source category exceeded any of the ecological benchmarks (either the LOAEL or NOAEL). Based on the results of our screening analysis for risks to the environment, we also proposed that the current standards prevent an adverse environmental effect.

2. How did the risk review change for the Phosphate Fertilizer Production source category?

The residual risk review for the Phosphate Fertilizer Production source category did not change since proposal (79 FR 66512). Accordingly, we are not tightening the standards under section 112(f)(2) based on the residual risk review, and are thus readopting the existing standards under section 112(f)(2).

3. What key comments did we receive on the risk review, and what are our responses?

The comments received on the proposed residual risk review were generally supportive of our determination of risk acceptability and ample margin of safety analysis. However, we received several comments requesting we make changes to the residual risk review, including:

- Update the residual risk review with the recommendations and information from the NAS;
- Incorporate the best currently available information on children's exposure to lead, and go beyond using the 2008 Lead NAAQS;
- Reevaluate whether the residual risk review is consistent with the key recommendations made by the SAB;
- Clarify in the rulemaking docket that data received by industry were commensurate with the relevant statutory obligations;
- Revise HF emission data because they are not representative of actual HF emissions, but rather overestimate emissions causing the residual risk review to have an overly conservative bias;
- Reconsider the assumption used in the NESHAP residual risk assessment that all chromium is hexavalent chromium;
- Revise certain stack parameters used in the analysis;
- Clarify meteorological data used in the analysis;
- Adequately explain rationale for the maximum 1-hour emission rate used for determining potential acute exposures;
- Clarify the selection of ecological assessment endpoints; and
- Provide some quantitative or qualitative rationale for the characterization of the exposure modeling uncertainty.

We evaluated the comments and determined that no changes were needed. Since none of these comments had an effect on the final rule, their summaries and corresponding EPA responses are not included in this preamble. A summary of these comments and our responses can be found in the Comment Summary and Response document available in the docket for this action (EPA–HQ–OAR–2012–0522).

4. What is the rationale for our final approach and final decisions for the risk review?

For the reasons explained in the proposed rule, we determined that the risks from the Phosphate Fertilizer Production source category are acceptable, the current emissions standards provide an ample margin of safety to protect public health, and prevent an adverse environmental effect. Since proposal, neither the risk assessment nor our determinations regarding risk acceptability, ample margin of safety or adverse environmental effects have changed. Therefore, pursuant to CAA section 112(f)(2), we are finalizing our residual risk review as proposed.

B. Technology Review for the Phosphate Fertilizer Production Source Category

1. What did we propose pursuant to CAA section 112(d)(6) for the Phosphate Fertilizer Production source category?

Pursuant to CAA section 112(d)(6), we conducted a technology review, which focused on identifying and evaluating developments in practices, processes, and control technologies for the emission sources in the Phosphate

Fertilizer Production source category. At proposal, we did not identify cost-effective developments in practices, processes, or control technologies that warrant revisions to the NESHAP for this source category. More information concerning our technology review can be found in the memorandum, ''CAA Section 111(b)(1)(B) and 112(d)(6) Reviews for the Phosphate Fertilizer Production and Phosphate Fertilizer Production Source Categories,'' which is available in the docket, and in the preamble to the proposed rule, 79 FR 66538–66539.

2. How did the technology review change for the Phosphate Fertilizer Production source category?

The technology review for the Phosphate Fertilizer Production source category did not change since proposal (79 FR 66512). Therefore, we are not revising NESHAP subpart BB based on the technology review.

3. What key comments did we receive on the technology review, and what are our responses?

Commenters agreed with our conclusion that there are no new cost-effective developments in practices, processes, or control technologies that can be applied to the Phosphate Fertilizer Production source category that would reduce HAP emissions below current levels.

4. What is the rationale for our final approach for the technology review?

For the reasons explained in the proposed rule, we concluded that additional standards are not necessary pursuant to CAA section 112(d)(6); therefore, we are not finalizing changes to NESHAP subpart BB as part of our technology review.

C. NSPS Review for the Phosphate Fertilizer Production Source Category

The NSPS review focused on the emission limitations that have been adequately demonstrated to be achieved in practice, taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements. Determining the BSER that has been adequately demonstrated and the emission limitations achieved in practice necessarily involves consideration of emission reduction methods in use at existing phosphate fertilizer production plants. To determine the BSER, the EPA performed an extensive review of several recent sources of information including a thorough search of the RBLC, section 114 data received from industry and other relevant sources.

Our review considered the emission limitations that are currently achieved in practice, and found that more stringent standards are not achievable for this source category. When evaluating the emissions from various process lines, we observed differences in emissions levels, but did not identify any patterns in emission reductions based on control technology configuration. More information concerning our NSPS review can be found in the memorandum, ''CAA Section 111(b)(1)(B) and 112(d)(6) Reviews for the Phosphoric Acid Manufacturing and Phosphate Fertilizer Production Source Categories.'' Though some of the sources are emitting at levels well below the current NSPS, other sources are not. We evaluated emissions based on control technologies and practices used by facilities, and found that the same technologies and practices yielded different results for different facilities. Therefore, we determined that we cannot conclude that new and modified sources would be able to achieve a more stringent NSPS. As explained in the proposed rule, all Phosphate Fertilizer Production NSPS (under subpart V, subpart W, and subpart X) emission sources, and the control technologies that would be employed, are the same as those for the NESHAP regulating phosphate fertilizer plants, such that we reached the same conclusion that there are no identified developments in technology or practices that results in cost-effective emission reductions strategies. Therefore, we are finalizing our determination that revisions to NSPS subpart V, subpart W, and subpart X standards are not appropriate pursuant to CAA section 111(b)(1)(B).

D. Startup, Shutdown, and Malfunction Provisions for the Phosphate Fertilizer Production Source Category

1. What SSM provisions did we propose for the Phosphate Fertilizer Production source category?

To address the U.S. Court of Appeals for the District of Columbia Circuit vacatur of portions of the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM, *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), we proposed to revise and add certain provisions to the NESHAP subpart BB. We proposed to revise the General Provisions table (appendix A of NESHAP subpart BB) to change several references related to requirements that apply during periods of SSM. We also proposed to add the following provisions to the rule: (1) Work practice standards for periods of startup and shutdown in lieu of numeric emission limits; (2) the general duty to minimize emissions at all times; (3) performance testing conditions requirements; (4) site-specific monitoring plan requirements; and (5) malfunction recordkeeping and reporting requirements. These proposed changes are discussed in more detail in section V.E of this preamble where we describe these same proposed changes for NESHAP subpart AA.

2. How did the SSM provisions change for the Phosphate Fertilizer Production source category?

We are finalizing the proposed work practice standards for periods of startup and shutdown; however, in consideration of comments received during the public comment period for the proposed rulemaking (as discussed in sections VI.D.3.a and VI.D.3.b of this preamble), we are making changes to this work practice in order to clarify the standard applies in lieu of numeric emission limits and how compliance with the standard is demonstrated. Additionally, as discussed in section VI.D.3.c of this preamble, we added definitions of ''startup'' and ''shutdown'' to provide additional clarity regarding when startup begins and ends, and when shutdown begins and ends.

3. What key comments did we receive on the SSM provisions, and what are our responses?

Comments were received regarding the proposed revisions to remove the SSM exemptions for the Phosphate Fertilizer Production source category, and the proposed work practice standards for periods of startup and shutdown. The following is a summary of some of the comments specific to the proposed work practice standards and our response to those comments. Other comments and our specific responses to those comments can be found in the Comment Summary and Response document available in the docket for this action (EPA–HQ–OAR–2012–0522).

a. Work Practice Standard In Place Of Emission Limits—Comment. One commenter argued that the EPA should specify that the proposed work practices for plant startup and shutdown periods apply ''in lieu of'' any other emission standards, and that such periods should not be counted for testing, monitoring, or operating parameter requirements. The commenter noted that the proposed rule at 40 CFR 63.622(d) requires the use of work practices ''to demonstrate compliance with any emission limits'' during periods of startup and shutdown. The commenter agrees with the EPA's conclusion that it is not feasible to apply numeric limits to startup and shutdown because certain variables required to calculate emissions would be zero during such periods. The commenter also agreed with the EPA that existing emission control devices would still be effective during periods of startup or shutdown, if activated. However, the commenter recommended that the rule should clarify that startup and shutdown events should not be required to comply with the monitoring and operating parameter requirements because startup and shutdown events generally are not representative operating conditions for other compliance purposes, such as emissions testing. Instead, the commenter, as well as a second commenter, recommended that because the startup and shutdown periods are not representative, the rule should only require that (1) All emission control devices be kept active, and (2) owners and operators follow the general duty to control emissions, and owners and operators should not be required to monitor operating parameters during startup and shutdown periods.

The commenter argued that the approach in the proposed rule at 40 CFR 63.622(d) to require the use of work practices ''to demonstrate compliance with any emission limits'' during periods of startup and shutdown is ''directly inconsistent'' with the approach that the EPA has applied to other source categories, where such practices clearly were prescribed ''in lieu of'' numeric emission limits that would otherwise apply. (The commenter cites, for example, 78 FR 10015, February 12, 2013.) According to the commenter, the EPA made it clear in other industries' rules that such work practice standards apply ''in place of'' or ''in lieu of'' numeric standards, including with respect to monitoring and recordkeeping requirements. (See id. at 10013 and 10015.) The commenter argues that according to the preamble language cited for those other industries, ''there will no longer be a numeric emission standard applicable during startup and shutdown,'' and the EPA recognizes that ''the recordkeeping requirement must change to reflect the content of the work practice standard'' (Id. at 10014).

Therefore, the commenter recommended that the EPA should clearly explain that work practices are not applied to ''demonstrate compliance'' with numeric limits under subpart BB, which the EPA acknowledges are ''not feasible'' for startup and shutdown periods, and, instead, the work practices should be written to apply ''in lieu of'' the numeric limits during those periods. The commenter argues that without this clarification, it will appear that both the numeric standards and the work practice standards would apply during startup and shutdown. The commenter suggests that this can be corrected in the rule by using the ''in lieu of'' language used for other industries.

Response. The commenter is correct that our intention at proposal was that the numeric emission limits would not apply during periods of startup and shutdown, but that facilities would comply with the work practice instead. We did not intend for the work practice to be a method to demonstrate compliance with the emission limit. We are replacing the phrasing ''to demonstrate compliance'' with ''in lieu of'' as this language is more consistent with our original intent. Accordingly, in the final rule, 40 CFR 63.622(d) specifies that the emission limits of 40 CFR 63.622(a) do not apply during periods of startup and shutdown. Instead, owners and operators must follow the work practice specified in 40 CFR 63.622(d). See section VI.D.3.b of this preamble for our response to commenters argument that owners and operators should not be required to monitor operating parameters during startup and shutdown periods.

b. Applicability of Operating Limits—Comment. Two commenters recommended that the EPA amend the rule to make clear that the work practice standards for startup and shutdown also apply in lieu of the parametric monitoring requirements set forth in NESHAP subpart BB and make explicit that parametric operating requirements do not apply during times of startup and shutdown.

One commenter argued that when the EPA established the flow rate and pressure drop parametric monitoring requirements in its 1999 final rule, the EPA concluded that requiring continuous monitoring of these parameters ''help[ed] assure continuous compliance with the emission limit'' (64 FR 31365, June 10, 1999). The commenter also asserted that the rule specifies that ''[t]he emission limitations and operating parameter requirements of this subpart do not apply during periods of startup, shutdown, or malfunction . . . '' (40 CFR 63.620(e)). The commenter argued that this was a reasonable action because the operating parameter ranges are established during annual performance tests, and these tests cannot be performed during startup and shutdown conditions.

The commenter suggested that in the proposed rule, the EPA exempted compliance with the emission limits during startup and shutdown periods, imposed work practice standards in lieu thereof, and retained the prohibition on conducting a performance test during periods of startup or shutdown (79 FR 66582 (proposed 40 CFR 63.626(d)). The commenter suggested that the proposed rule is silent on the applicability of the parametric monitoring requirements during startup and shutdown. The commenter asserted that because the parametric monitoring provisions provide an inference of compliance with the emission limits (64 FR 31365, June 10, 1999), and these emission limits do not apply during startup and shutdown, the commenter concluded that the parametric monitoring provisions similarly should not apply during startups and shutdowns.

The commenters pointed to two recent EPA NESHAP rulemakings to support their conclusion. First, the commenters argued that in its industrial, commercial and institutional boilers and process heaters NESHAP reconsideration proposal (hereinafter, the ''Boiler NESHAP''), the EPA, responding to a comment soliciting clarification ''that the operating limits and opacity limits do not apply during periods of startup and shutdown,'' stated that with the finalization of work practice standards, ''EPA agrees that the requested clarification is what was intended in the final rule'' (76 FR 80598 and 80615, December 23, 2011.) The commenters asserted that to this end, in its response to the reconsideration, the EPA made clear that affected sources must comply with ''all applicable emissions and operating limits at all times the unit is operating except for periods that meet the definitions of startup and shutdown in this subpart, during which times you must comply with these work practices'' (78 FR 7138 and 7142, January 31, 2013.) The commenters noted that in the Boiler NESHAP, the EPA required the implementation of work practice standards in lieu of compliance with the operating parameter requirements during startup and shutdown by (1) Excluding periods of startup and shutdown from the averaging period (Id. at 7187, 40 CFR 63.7575, the definition of a 30-day rolling average'' excludes ''hours during startup and shutdown''), and (2) expressly stating that the ''standards'' (the emission limits and operating requirements) do not apply during periods of startup or shutdown. (Id. at 7163, 40 CFR 63.7500(f), titled ''What emission limitations, work practice standards, and operating limits must I meet?'' applies ''at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 of this subpart'').

Second, the commenters argued that in its Portland Cement NESHAP, the EPA specified an operating limit for kilns, identified as a temperature limit established during a performance test, and that the temperature limit applied at all times the raw mill is operating, ''except during periods of startup and shutdown'' (78 FR 10039, February 12, 2013, 40 CFR 63.1346(a)(1).) Further, for the continuous monitoring requirements, including operating limits, the Portland Cement NESHAP required operating of the monitoring system at all times the affected source is operating, ''[e]xcept for periods of startup and shutdown'' (Id. at 10041, 40 CFR 63.1348(b)(1)(ii).)

The commenters argued that given the EPA's conclusion in the Proposed Rule that the emission limits should not apply during startup and shutdown, and because the parametric monitoring requirements are established during a performance test (which cannot be performed during a startup or a shutdown) and used to infer compliance with the emission limits, the EPA should make clear in the final rule that the operating parameters requirements do not apply during a startup or a shutdown. The commenter recommended that the EPA should make this explicit: (1) In the operating and monitoring requirement section of subpart BB (proposed 40 CFR 63.625), and (2) by defining the averaging period (currently daily) as excluding periods of startup and shutdown (Proposed 40 CFR part 63, subpart BB, Table 4). As an alternative, the commenters recommended that if the EPA continues to require compliance with the parametric monitoring requirements during startup and shutdown periods, then the EPA should adopt a longer averaging period, from daily to 30 days, to allow for the effects of startups and shutdowns to be reduced by a longer period of steady-state operations. The commenter noted that the Boiler NESHAP has a 30-day averaging period for pressure drop and liquid flow rate, and excludes periods of startup and shutdown from the averaging period (40 CFR 63.7575, definition of ''30-day rolling average'' and 40 CFR part 63, subpart DDDDD, Table 4). The commenter stated that a 30-day averaging period would be substantially more stringent than the Boiler NESHAP approach since it would include periods of startup and shutdown, while at the same time avoid misleading ''exceedances'' caused by the inclusion of periods of startup and shutdown compared to daily average parametric limits.

Response. We disagree with the commenters about the applicability of the operating limits. Based on these comments, we have clarified in the final rule at 40 CFR 63.622(d) that to comply with the work practice during periods of startup and shutdown, facilities must monitor the operating parameters specified in Table 3 to subpart BB and comply with the operating limits specified in Table 4 of subpart BB. The purpose of the work practice is to ensure that the air pollution control equipment that is used to comply with the emission limit during normal operations is operated during periods of startup and shutdown. Monitoring of control device operating parameters is necessary to demonstrate compliance with the work practice. We have concluded that it is reasonable for the control device at phosphate fertilizer production processes to meet the same operating limits during startup and shutdown that apply during normal operation, and that it is not necessary to specify different averaging times for periods of startup and shutdown. Meeting the operating limits of Table 4 of subpart BB will ensure that owners and operators meet the General Duty requirement to operate and maintain the affected source and associated air pollution control equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions.

The analogies that the commenters made to the Boiler NESHAP and the Portland Cement NESHAP are not relevant to this rulemaking. In each rulemaking, we consider the feasibility of applying standards during startup and shutdown based on relevant process considerations for each source category, the pollutants regulated, and control devices on which the rule is based. In developing this rule, we obtained information on the operation of control devices during startup and shutdown periods in the CAA section 114 survey issued to the phosphate fertilizer production industry. Based on survey results, we concluded that for this source category, control devices (*i.e.,* absorbers) could be operated during periods of startup and shutdown. We found no indication that process operations during startup and shutdown would interfere with the ability to operate the relevant control devices according to good engineering practice. Moreover, the commenters provided no technical justification as to why a different operating limit is needed during startup and shutdown.

Regarding the comparison to the industrial boiler NESHAP, the operation of boilers and their associated control devices are different than phosphate fertilizer production plants. While boiler control devices do not have to comply with specific operating limits during startup or shutdown, they must meet a work practice that includes firing clean fuels, operating relevant control devices (*e.g.,* absorbers) as expeditiously as possible, and monitoring the applicable operating parameters (*e.g.,* flow rate) to demonstrate that the control devices are being operated properly. The EPA currently is reconsidering the control requirements for industrial boilers during startup and shutdown (80 FR 3090, January 21, 2015). In the proposed action on reconsideration, we pointed out that some of the control devices used for boilers cannot be operated during the full duration of startup and shutdown because of safety concerns and the possibility of control equipment degradation due to fouling and corrosion. The control devices used for phosphate fertilizer production do not pose these same risks. Likewise, the fact that the Portland Cement NESHAP does not require monitoring of kiln temperature during startup and shutdown is not relevant. The Portland Cement NESHAP requires maintaining a kiln temperature as part of the MACT operating limit. The operating limit for Portland Cement does not apply during startup and shutdown because it is not physically possible to maintain a constant temperature during startup and shutdown of a kiln. In contrast, the feasibility of operating the control devices used to control HAP emissions from phosphate fertilizer production is not limited by specific process operating conditions. Therefore, it is feasible to operate the devices during startup and shutdown, and we have determined that it is reasonable to do so considering cost, nonair health and environmental impacts, and energy requirements.

c. Definition of Startup and Shutdown—Comment. Several commenters stated that it is not feasible to base the conclusion of a ''shutdown'' on the point at which all feed has ''been processed.'' Instead, they suggested that the EPA should clarify the work practice standard of keeping all emission control equipment active during shutdowns. The commenters reported that facilities in the industry consider the commencement of ''shutdown'' as the moment at which the plant ceases adding feed to the affected process, rather than basing shutdown on when all feed materials have been processed through the process. The commenters recommended that the EPA should define ''shutdown'' to begin when the facility ceases adding feed to an affected process line, and to conclude when the affected process line equipment is deactivated, even though some feed or residues may still be present within particular parts of the process.

One of the commenters also noted that it is common practice to have short-term shutdown of process inputs for temporary maintenance work (including work on emission control equipment) where the entire system is not emptied. In these cases, feed of phosphoric acid and ammonia to the process is suspended as is flow from the reactor to the granulator. The commenter argued that because the source of fluoride to the system has ceased and dust generating material flows are suspended, there should be no significant source of emissions to control, and it is not necessary to require the utilization of control devices until all feed material has been processed. Instead, the commenter recommended that an affected entity should be allowed to turn off control devices when reactor and granulator feeds have been stopped, unless the system is being emptied, in which case control devices should be required as long as the material handling system is in operation.

Response. We agree with the commenters that the rule needs to have a more precise definition of startup and shutdown that more clearly and reasonably establishes the times when the work practice applies and when the emission limits apply. Accordingly, we added a definition of ''startup'' and ''shutdown'' in the Definitions section of the final rule to specify when startup begins and ends, and when shutdown begins and ends.

Based on additional information provided by industry (see ''Email Correspondence Received After Comment Period re Startup Shutdown (May 5, 2015),'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522), we are including a definition of startup in the final rule. The final rule defines startup as commencing when any feed material is first introduced into an affected source and ends when feed material is fully loaded into the affected source. Regarding shutdown, we agree with the commenters that it is not feasible to process all feed material from a process prior to shutting down most equipment at a facility. Such requirement would imply that the control device must be operated after the shutdown ends. The final rule defines shutdown as commencing when the facility ceases adding feed to an affected source and ends when the affected source is deactivated, regardless of whether feed material is present in the affected source. This definition will address concerns about temporary shutdowns as well as shutdowns of longer duration.

In addition, the final rule at 40 CFR 63.622(d) specifies that any control device used at the affected source must be operated during the entire period of startup and shutdown, and must meet the operating limits in Table 4 of the rule.

4. What is the rationale for our final decisions for the SSM provisions?

For the reasons provided above and in the preamble for the proposed rule, we are finalizing the proposed revisions to the General Provisions table (appendix A of NESHAP subpart BB) to change several references related to requirements that apply during periods of SSM. For these same reasons, we are also finalizing the addition of the following proposed provisions to NESHAP subpart BB: (1) Work practice standards for periods of startup and shutdown in lieu of numeric emission limits; (2) the general duty to minimize emissions at all times; (3) performance testing conditions requirements; (4) site-specific monitoring plan requirements; and (5) malfunction recordkeeping and reporting requirements.

E. Other Changes Made to the Phosphate Fertilizer Production NESHAP and NSPS

1. What other changes did we propose for the Phosphate Fertilizer Production NESHAP and NSPS?

a. Clarifications to Applicability and Certain Definitions —i. NESHAP Subpart BB. As stated in the preamble to the proposed rule, to ensure the emission standards reflect inclusion of HAP emissions from all sources in the source category, we proposed to clarify the applicability of the NESHAP to include reaction products of ammonia and phosphoric acid, and not just diammonium and monoammonium phosphate.

For consistency between NESHAP subpart AA and NESHAP subpart BB, we also proposed conditions in NESHAP subpart BB that exclude (like NESHAP subpart AA does) the use of evaporative cooling towers for any liquid effluent from any wet scrubbing device installed to control HF emissions from process equipment. Lastly, we proposed to amend the definitions of ''diammonium and/or monoammonium phosphate process line,'' ''granular triple superphosphate process line,'' and ''granular triple superphosphate storage building'' to include relevant emission points, and to remove text from the applicability section that is duplicative of the revised definitions.

ii. NSPS Subpart V. We did not propose changes to applicability or definitions in NSPS subpart V.

iii. NSPS Subpart W. We proposed changing the word ''cookers'' as listed in 40 CFR 60.230(a) to ''coolers'' in order to correct the typographical error.

iv. NSPS Subpart X. We did not propose changes to applicability or definitions in NSPS subpart X.

b. Testing, Monitoring, Recordkeeping and Reporting—i. NESHAP Subpart BB. As stated in the preamble to the proposed rule, to provide flexibility, we proposed several monitoring options, including pressure and temperature measurements, as alternatives to monitoring of absorber differential pressure. We also proposed monitoring the absorber inlet gas flow rate along with the influent absorber liquid flow rate (and determining liquid-to-gas ratio) in lieu of monitoring only the absorber inlet liquid flow rate.

In addition, we proposed removing the requirement that facilities may not implement new operating parameter ranges until the Administrator has approved them, or 30 days have passed since submission of the performance test results. We proposed that facilities must immediately comply with new operating ranges when they are developed and submitted; and new operating ranges must be established using the most recent performance test conducted by a facility, which allows for changes in control device operation to be appropriately reflected.

We also proposed monitoring requirements for fabric filters in NESHAP subpart BB because we identified two processes that used fabric filters rather than wet scrubbing as control technology.

As stated in the preamble to the proposed rule, we modified the language for the conditions under which testing must be conducted to require that testing be conducted at ''maximum representative operating conditions'' for the process.[11]

In keeping with the general provisions for CMS (including CEMS and CPMS), we proposed the addition of a site-specific monitoring plan and calibration requirements for CMS. Provisions were also proposed that included electronic reporting of stack test data. We also

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[11] Based on the EPA memorandum, ''Issuance of the Clean Air Act National Stack Testing Guidance,'' dated April 27, 2009.

proposed modifying the format of NESHAP subpart BB to reference tables for emissions limits and monitoring requirements.

Finally, we proposed HF standards in NESHAP subpart BB by translating the current total fluoride limits (lb total F/ton P_2O_5 feed) into HF limits (lb HF/ton P_2O_5 feed). To comply with HF standards, we proposed that facilities use EPA Method 320.

ii. NSPS Subpart V. We proposed new monitoring and recordkeeping requirements for any granular diammonium phosphate plant that commences construction, modification or reconstruction after November 7, 2014 to ensure continuous compliance with the standard. As stated in the preamble to the proposed rule, to ensure that the process scrubbing system is properly maintained over time; ensure continuous compliance with standards; and improve data accessibility, we proposed the owner or operator establish an allowable range for the pressure drop through the process scrubbing system. We also proposed that the owner or operator keep records of the daily average pressure drop through the process scrubbing system, and keep records of deviations.

For consistency with terminology used in the associated NESHAP subpart BB, we proposed changing the term ''scrubbing system'' to ''absorber'' in NSPS subpart V.

iii. NSPS Subpart W. We proposed new monitoring and recordkeeping requirements for any TSP plant that commences construction, modification or reconstruction after November 7, 2014 to ensure continuous compliance with the standard. As stated in the preamble to the proposed rule, to ensure that the process scrubbing system is properly maintained over time; ensure continuous compliance with standards; and improve data accessibility, we proposed the owner or operator establish an allowable range for the pressure drop through the process scrubbing system. We also proposed that the owner or operator keep records of the daily average pressure drop through the process scrubbing system, and keep records of deviations.

For consistency with terminology used in the associated NESHAP subpart BB, we proposed changing the term ''process scrubbing system'' to ''absorber'' in NSPS subpart W.

iv. NSPS Subpart X. We proposed new monitoring and recordkeeping requirements for any GTSP storage facility that commences construction, modification or reconstruction after November 7, 2014 to ensure continuous compliance with the standard. As stated in the preamble to the proposed rule, to ensure that the process scrubbing system is properly maintained over time; ensure continuous compliance with standards; and improve data accessibility, we proposed the owner or operator establish an allowable range for the pressure drop through the process scrubbing system. We also proposed that the owner or operator keep records of the daily average pressure drop through the process scrubbing system, and keep records of deviations.

For consistency with terminology used in the associated NESHAP subpart BB, we proposed changing the term ''process scrubbing system'' to ''absorber'' in NSPS subpart X.

2. How did the provisions regarding these other proposed changes to the Phosphate Fertilizer Production NESHAP and NSPS change since proposal?

a. Clarifications to Applicability and Certain Definitions—i. NESHAP Subpart BB. In consideration of comments received during the public comment period for the proposed rulemaking, we are defining ''phosphate fertilizer process line'' and ''phosphate fertilizer production plant'' separately as discussed in section VI.E.3.a.i of this preamble. We are also revising rule language at 40 CFR 63.620(b)(1), 63.622(a), 63.622(a)(1), 63.622(a)(2), 63.625(a), 63.626(f), in Table 1, and in Table 2 to accommodate this change. We are also removing the proposed language ''includes, but is not limited to'' in the definition of DAP and/or MAP process line for reasons discussed in section VI.E.3.a.ii of this preamble.

ii. NSPS Subpart V. We are not making changes to applicability or definitions in NSPS subpart V.

iii. NSPS Subpart W. We are not making changes to applicability or definitions in NSPS subpart W.

iv. NSPS Subpart X. We are not making changes to applicability or definitions in NSPS subpart X.

b. Testing, Monitoring, Recordkeeping and Reporting.—i. NESHAP Subpart BB. We have not made any changes to our proposed determination that pressure drop is not an appropriate monitoring parameter for absorbers that are designed to operate with pressure drops of 5 inches of water column or less. However, in consideration of comments received during the public comment period for the proposed rulemaking, we are not adopting the proposed options to monitor: (1) The temperature at the wet scrubber gas stream outlet and pressure at the liquid inlet of the absorber, or (2) the temperature at the scrubber gas stream outlet and scrubber gas stream inlet. Instead, we have revised Table 3 of NESHAP subpart BB to require liquid-to-gas ratio monitoring for low-energy absorbers, and influent liquid flow and pressure drop monitoring for high-energy absorbers; and we are keeping liquid-to-gas ratio monitoring as an option for high-energy absorbers in the final rule. (See sections VI.E.3.b.i and VI.E.3.b.ii of this preamble for details.)

In addition to these revisions, we are making corrections at 40 CFR 63.627(a) to clarify the procedures for establishing a new operating limit based on the most recent performance test. We are also revising the requirements at 40 CFR 63.625(d)(1)(ii)(B) to remove the requirement that facilities must request and obtain approval of the Administrator for changing operating limits. (See section VI.E.3.b.iv and VI.E.3.b.v of this preamble for details.)

Also, for reasons discussed in the Comment Summary and Response document available in the docket, we are revising the annual testing schedule in the final rule at 40 CFR 63.626(b), and the terminology for ''maximum representative operating conditions'' in the final rule at 40 CFR 63.626(d).

We are not making any changes to the proposed addition of a site-specific monitoring plan and calibration requirements for CMS. We are also keeping the proposed term ''absorber'' in lieu of ''scrubber,'' as well as the proposed format of NESHAP subpart BB to reference tables for emissions limits and monitoring requirements.

Lastly, we are retaining the current total fluoride limits and not adopting the proposed HF standards and associated EPA Method 320 testing in NESHAP subpart BB (see section VI.E.3.c of this preamble for details).

ii. NSPS Subpart V. We are not making changes to the proposed monitoring and recordkeeping requirements for any granular diammonium phosphate plant that commences construction, modification or reconstruction after August 19, 2015 to ensure continuous compliance with the standard. We are also keeping the proposed term ''absorber'' in lieu of ''scrubbing system.''

iii. NSPS Subpart W. We are not making changes to the proposed monitoring and recordkeeping requirements for any TSP plant that commences construction, modification or reconstruction after August 19, 2015 to ensure continuous compliance with the standard. We are also keeping the proposed term ''absorber'' in lieu of ''process scrubbing system.''

iv. NSPS Subpart X. We are not making changes to the proposed monitoring and recordkeeping requirements for any GTSP storage facility that commences construction, modification or reconstruction after August 19, 2015 to ensure continuous compliance with the standard. We are also keeping the proposed term ''absorber'' in lieu of ''process scrubbing system.''

3. What key comments did we receive on the other changes to the Phosphate Fertilizer Production NESHAP and NSPS, and what are our responses?

Several comments were received regarding the proposed clarifications to applicability and certain definitions, revisions to testing, monitoring, recordkeeping and reporting, translation of total fluoride to HF emission limits, and revisions to other provisions for the Phosphate Fertilizer Production source category. The following is a summary of several of these comments and our response to those comments. Other comments received and our responses to those comments can be found in the Comment Summary and Response document available in the docket for this action (EPA–HQ–OAR–2012–0522).

a. Applicability Clarifications and Certain Definitions—i. Phosphate Fertilizer Process Line—Comment. Several commenters disapproved of the proposed expansion of the applicability provision for DAP and MAP process lines in 40 CFR 63.620(b)(1) to include ''any process line that produces a reaction product of ammonia and phosphoric acid.'' One commenter asserted that the expanded language could include production of non-granular products that were in existence since the original NESHAP but not regulated by it, and EPA provided no basis for expansion of applicability to bring in these processes now. Other commenters also reiterated that the proposed applicability provision for DAP and MAP process lines was vague and overbroad and would inadvertently regulate any process that combines ammonia and phosphoric acid regardless of the end-product or purpose of facility. One commenter recommended a change in the definition to clarify that subpart BB applies specifically to solid, granulated phosphate products to avoid inclusion of liquid fertilizer products in the proposed rule.

Response. The Agency agrees with the commenter that the proposed language could be interpreted to include production of non-granular products at a phosphate fertilizer production plant. It was not our intent to expand the applicability of 40 CFR subpart BB to include the production of non-granular products at a phosphate fertilizer production plant; therefore, we are revising the definitions of ''phosphate fertilizer process line'' and ''phosphate fertilizer production plant'' in the final rule at 40 CFR 63.621 to reference granular phosphate fertilizer. Also, the definitions of phosphate fertilizer process line and phosphate fertilizer production plant were defined together at proposal (phosphate fertilizer process line or production plant), but are defined separately in the final rule for clarity. The definition of phosphate fertilizer process line means ''any process line that manufactures a granular phosphate fertilizer by reacting phosphoric acid with ammonia. A phosphate fertilizer process line includes: Reactors, granulators, dryers, coolers, screens, and mills.'' The definition of phosphate fertilizer production plant means ''any production plant that manufactures a granular phosphate fertilizer by reacting phosphoric acid with ammonia.''

As an outgrowth of this comment, the Agency revised rule language surrounding the use of ''phosphate fertilizer process line,'' to create clarity and consistency in rule language. Specifically, where the phrase ''diammonium and/or monoammonium phosphate process line and any process line that produces a reaction product of ammonia and phosphoric acid'' was used at proposal, this phrase now reads ''phosphate fertilizer process line (*e.g.,* diammonium and/or monoammonium phosphate process line)'' in the finalized rule. This phrasing was incorporated into final rule language at 40 CFR 63.620(b)(1), 63.622(a), 63.622(a)(1), 63.622(a)(2), 63.625(a), 63.626(f), in Table 1, and in Table 2.

ii. ''Includes, but is Not Limited to''—Comment. A commenter remarked that incorporating the language ''includes, but is not limited to'' in the definition of DAP and/or MAP process line is overly broad and creates ambiguity. They stated that industry should have certainty as to the applicability and scope of the rule, but the language ''includes, but is not limited to'' creates uncertainty as to where the affected equipment begins and ends for purposes of demonstrating compliance.

Response. We agree that this language creates overly broad process line definitions and can lead to regulatory uncertainty for affected sources. Therefore, we are not finalizing the language ''includes, but is not limited to'' in the definition of DAP and/or MAP process line.

b. Testing, Monitoring, Recordkeeping and Reporting—i. Pressure Drop Across Absorber—Comment. Several commenters requested the EPA delete the requirement that pressure drop across an absorber must be greater than 5 inches of water in order to use the option of measuring pressure drop as an operating parameter. These commenters contended that the EPA has not articulated any basis for the requirement. These commenters provided data demonstrating that units operate in compliance with the emission standards when the pressure drop across an absorber is less than 5 inches of water. One of these commenters expressed safety concerns associated with operating scrubbers at higher range pressure drop settings, citing that one of its facilities has experienced the entrainment of moisture within the absorbing tower when operating at pressure drops in excess of 8 inches of water, and another has experienced the buildup of excessive fumes on the digester floor when operating the digester scrubber as high as 6 inches of water.

Response. The Agency maintains its determination that pressure drop is not an appropriate monitoring parameter for absorbers that do not use the energy from the inlet gas to increase contact between the gas and liquid in the absorber (see ''Use of Pressure Drop as an Operating Parameter,'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522). Therefore, we are not revising this proposed amendment. For further explanation please see our response to the identical comment that was made for NESHAP subpart AA in section V.F.3.b.i of this preamble.

ii. Absorber Monitoring Options—Comment. Several commenters called attention to the options of either measuring: (1) The temperature at the wet scrubber gas stream outlet and pressure at the liquid inlet of the absorber, or (2) the temperature at the scrubber gas stream outlet and scrubber gas stream inlet. One of these commenters said that they do not believe monitoring gas temperature in locations of large ambient temperature ranges would provide accurate monitoring of the absorbers performance. The commenter argued that temperature and pressure probes would be very susceptible to scaling issues. In addition, this commenter contended that liquid inlet pressure does not provide any additional monitoring of the absorber performance, since the inlet liquid flow rate is already measured and monitored. Another commenter contended that the EPA has not provided any data or analysis to show that there is a correlation between temperature and emissions; the commenter stated that they were not aware of any data suggesting a relationship between exit temperature and emissions, or that monitoring temperature difference across an absorber would be effective. One of these commenters argued that they were not in a position to evaluate the difficulties associated with performing the associated monitoring and establishing the requisite operating ranges.

Response. Absorber outlet gas temperature is often used to indicate a change in operation for absorbers used to control thermal processes. Because this source category does not use a thermal process to produce fertilizer, the Agency agrees with the commenters that temperature is not an appropriate monitoring parameter for absorbers used in this source category, and has removed these monitoring options from Table 3 of the final rule (NESHAP subpart BB). However, in light of this comment, the Agency has revised Table 3 of NESHAP subpart BB to require liquid-to-gas ratio monitoring for low-energy absorbers (*i.e.,* absorbers that are designed to operate with pressure drops of 5 inches of water column or less) in lieu of monitoring influent liquid flow and pressure drop through the absorber. Furthermore, the Agency has revised Table 3 of NESHAP subpart BB to require influent liquid flow and pressure drop monitoring for high-energy (*i.e.,* high pressure drop) absorbers, such as venturi scrubbers; and we are keeping liquid-to-gas ratio monitoring as an option for high-energy absorbers in the final rule. For further explanation please see our response to the identical comment that was made for NESHAP subpart AA in section V.F.3.b.ii of this preamble.

iii. Acceptable Range From Baseline Average Value—Comment. One commenter requested that the EPA revise 40 CFR 63.625(d)(1)(ii)(B) to have similar wording to 40 CFR 63.625(d)(1)(ii)(A), in which the allowable parametric limits may encompass up to +/−20 percent of the of the baseline average values for the series of tests used under this option; that is, the parametric limit may extend −20 percent below the lowest baseline average and up to +20 percent above the highest baseline average from the series of performance tests used for this option.

Response. The Agency determined that it is not necessary to revise 40 CFR 63.625(d)(1)(ii)(B) to allow for a ±20 percent operating margin, as this commenter requests, because this provision already allows owners or operators to establish an operating limit range for a control device without having to apply an operating margin, such as ±20 percent. Owners or operators that use an absorber or a WESP to comply with the emission limits (and monitor pressure drop across each absorber or secondary voltage for a WESP) have two options to establish operating limits for demonstrating continuous compliance: (1) At 40 CFR 63.625(d)(1)(ii)(A), the operating limits may be determined using the most recent performance test and applying an operating margin of ±20 percent (*e.g.,* during the three test runs conducted for an owner's or operator's most recent performance test that demonstrated compliance with the emission limit, the arithmetic average of the absorber pressure drops recorded was 7 inches of water; therefore, under this option, the owner's or operator's operating limit range for this absorber would be 5.6 to 8.4 inches of water, or ±20 percent of 7); or (2) at 40 CFR 63.625(d)(1)(ii)(B), owners or operators may establish operating limit ranges based upon baseline values of operating parameters established in either historic performance tests or performance tests conducted specifically to establish such ranges (*e.g.,* an owner or operator could choose to conduct two consecutive performance tests consisting of three test runs each and if the owner or operator demonstrates compliance with the emission limit while operating an absorber with a pressure drop of 6 inches of water during the first performance test, and then in the second performance test the owner or operator demonstrates compliance with the emission limit while operating an absorber with a pressure drop of 10 inches of water, the owner's or operator's operating limit range for this absorber would be 6 to 10 inches of water under this option). Additionally, the rule permits owners or operators to undertake additional performance testing (for either option) to establish control device operating limits which reflect compliance with the emission limit for the full range of operating conditions of the control device. Therefore, the Agency has determined that no change to 40 CFR 63.625(d)(1)(ii)(B) is warranted.

iv. Operating Range Established From a Previous Test—Comment. One commenter stated that 40 CFR 63.627(a) is somewhat ambiguous, tending to suggest that affected facilities would be immediately required to implement new equipment operating ranges following a source test, even if operating conditions from previous source tests demonstrated compliance with fluoride emission standards. The commenter argued that there is no reason that a new performance test at a new operating range should invalidate a previous performance test at a different operating range.

Response. The Agency has clarified in the final rule at 40 CFR 63.627(a) that during the most recent performance test, if owners or operators demonstrate compliance with the emission limit while operating their control device outside the previously established operating limit, then limits must be established. Owners or operators must establish a new operating limit based on that most recent performance test and notify the Administrator that the operating limit changed based on data collected during the most recent performance test. For further explanation please see our response to the identical comment that was made for NESHAP subpart AA in section V.F.3.b.iii of this preamble.

v. Approving Operating Ranges—Comment. Several commenters support the EPA's proposal to eliminate the requirement that facilities may not implement new operating parameter ranges until the Administrator has approved them, or 30 days have passed since submission of the performance test results. However, two of these commenters pointed out that the EPA did not make the same allowance in 40 CFR 63.625(d)(1)(ii)(B), where a series of tests (potentially including historical tests) are used to establish an operating range. A commenter pointed out that 40 CFR 63.625(d)(1)(ii)(B), as proposed, does not provide the 30-day default period for the effectiveness of the new ranges if the EPA Administrator does not act; therefore, as currently set forth in the proposed rule, sources will be left in limbo waiting for the EPA Administrator to respond before they can implement new ranges. A commenter suggested that the EPA revise the proposed regulatory language to require submission of the new ranges to EPA, but delete the requirement to request and obtain EPA's approval of the new ranges. Similarly, another commenter requested the EPA clarify the process for establishing new equipment operating ranges following source performance testing. This commenter contended that facilities should have the ability to update operating parameters if they desire based on source testing, and the facility should be required to submit the new ranges, but not be required to obtain EPA's approval of the new ranges.

In addition, a commenter requested that the EPA clarify how revising the proposed regulatory language to require submission of the new ranges to the

EPA, but deleting the requirement to request and obtain EPA's approval of the new ranges, will affect possible obligations to undertake permit modifications of title V permits under 40 CFR part 70. This commenter stated that such administrative processes are not fully anticipated in the proposed rule.

Response. In the proposed NESHAP subpart BB, the Agency intended that facilities not be required to obtain approval, and instead, immediately comply with a new operating limit when it is developed and submitted to the Administrator. Therefore, the requirements at 40 CFR 63.625(d)(1)(ii)(B) have been revised in the final rule, as the commenter requests, to remove the requirement that facilities must request and obtain approval of the Administrator for changing operating limits. Furthermore, the Agency suggests that the title V permit be modified as soon as the Administrator is notified of a change in an operating limit. The Agency acknowledges that corrections and modifications to permit applications could become a problem for a facility, particularly if the Administrator determines the operating limit is not appropriate after a facility has already applied for the change to be made in their air permit; however, we expect this scenario to be rare.

c. Translation of Total Fluoride to HF Emission Limits—Comment. Several commenters expressed concerns regarding the methodology for expressing the existing total fluoride limits in terms of HF (refer to section V.F.3.c of this preamble for a summary of comments received on this topic).

Response. In light of information provided by commenters, the Agency has re-evaluated the proposed revision to the standard and determined that EPA Method 320 is not an appropriate test method for accurately measuring HF emissions from process lines at this specific source category due to the complex and often incomplete chemical reactions with silicon compounds in these sources. Accordingly, we are not adopting the proposed HF standards, and instead we are retaining the existing total fluoride limits for all emission sources in subpart BB. For further explanation on this determination, refer to section V.F.3.c of this preamble. Although, at the present time, the Agency is not finalizing HF standards in NESHAP subpart BB, it may be possible to do so in a future rulemaking with additional data and specificity on monitoring requirements.

4. What is the rationale for our final decisions regarding these other changes to the Phosphate Fertilizer Production NESHAP and NSPS?

For the reasons provided above and in the preamble for the proposed rule, we are finalizing the proposed requirement in NESHAP subpart BB that pressure drop across an absorber must be greater than 5 inches of water in order to use the option of measuring pressure drop as an operating parameter; and other proposed clarifications and corrections.

Additionally, for the reasons provided above, we are making the revisions, clarifications and corrections noted in section VI.E.2 in the final rules for NESHAP subpart BB, NSPS subpart V, NSPS subpart W, and NSPS subpart X.

VII. Summary of Cost, Environmental, and Economic Impacts and Additional Analyses Conducted

A. What are the affected facilities?

We anticipate that the 13 facilities currently operating in the U.S. will be affected by these amendments. We do not expect any new facilities to be constructed or expanded in the foreseeable future.

B. What are the air quality impacts?

We anticipate HF emissions reductions as a result of one facility installing controls on its oxidation reactor to comply with the SPA total fluoride limit. However, we do not have emissions data for its oxidation reactor to calculate these reductions. In addition, the revised rule will mitigate future increases of Hg emissions from phosphate rock calciners by requiring compliance with numeric emission limits.

C. What are the cost impacts?

We have estimated compliance costs for all existing sources to add the necessary controls and monitoring devices, perform inspections, and implement recordkeeping and reporting requirements to comply with the final rules. Based on this analysis, we anticipate an overall total capital investment of $346,000, with an associated total annualized cost of approximately $294,000. We do not anticipate the construction of any new phosphoric acid manufacturing plants or phosphate fertilizer production facilities in the next 5 years. Therefore, there are no anticipated new source cost impacts. We estimated the cost to install a venturi scrubber to meet the SPA process line total fluoride standard, when oxidation reactor emissions are included, for one facility. For all emission sources, we calculated capital and annual costs for testing, monitoring, recordkeeping, and reporting. The memorandum, ''Control Costs and Emissions Reductions for Phosphoric Acid and Phosphate Fertilizer Production Source Categories—Final Rule,'' which is available in the docket for this action, documents the control cost analyses.

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, we also examine impacts on other markets. Both the magnitude of costs needed to comply with the rule and the distribution of these costs among affected facilities can have a role in determining how the market will change in response to the rule. We project that no facility will incur significant costs.

Because no small firms will incur control costs, there is no significant impact on small entities. Thus, we do not expect this regulation to have a significant impact on a substantial number of small entities.

E. What are the benefits?

The revised rule will mitigate future increases of Hg emissions from phosphate rock calciners by requiring compliance with numeric emission limits. These avoided emissions will result in improvements in air quality and reduced negative health effects associated with exposure to air pollution of these emissions. However, we have not quantified or monetized the benefits of reducing these emissions for this rulemaking because information is not available to monetize potential benefits and we are not aware of any new phosphate rock calciners that will be constructed in the next three years.

F. What analysis of environmental justice did we conduct?

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practical and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations in the U.S.

The EPA has determined that this rule will not have disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. To gain a better understanding of the source category and near source populations, the EPA conducted a proximity analysis on phosphate facilities to identify any overrepresentation of minority, low income, or indigenous populations. This analysis only gives some indication of the prevalence of sub-populations that may be exposed to air pollution from the sources; it does not identify the demographic characteristics of the most highly affected individuals or communities, nor does it quantify the level of risk faced by those individuals or communities.

The proximity analysis reveals that most demographic categories are below or within 20 percent of their corresponding national averages. The two exceptions are the minority and African American populations. The ratio of African Americans living within 3 miles of any source affected by this rule is 131 percent higher than the national average (29 percent versus 13 percent). The percentage of minorities living within 3 miles of any source affected by this rule is 37 percent above the national average (35 percent versus 28 percent). The large minority population is a direct result of the higher percentage of African Americans living near these facilities (the other racial minorities are below or equal to the national average). However, as noted previously, we found the risks from these source categories to be acceptable for all populations.

The changes to the standard increase the level of environmental protection for all affected populations by ensuring no future emission increases from the source categories. The proximity analysis results and the details concerning their development are presented in the October 2012 memorandum, ''Environmental Justice Review: Phosphate Fertilizer Production and Phosphoric Acid,'' a copy of which is available in Docket ID No. EPA–HQ–OAR–2012–0522.

G. What analysis of children's environmental health did we conduct?

While this action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997), we note that the current standards provide an ample margin of safety to protect public health. Consideration of children's health is accounted for in our risk analyses, which compare projected exposures to various health benchmarks that are based on the most sensitive populations.

VIII. Statutory and Executive Order Reviews

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

This action is not a significant regulatory action and was, therefore, not submitted to the Office of Management and Budget (OMB) for review. The EPA analyzed the potential costs and benefits associated with this action. The results are presented in sections VII.C and E of this preamble.

B. Paperwork Reduction Act (PRA)

The information collection activities in these rules 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 1790.06. 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.

We are finalizing new paperwork requirements to the Phosphoric Acid Manufacturing and Phosphate Fertilizer Production source categories in the form of additional requirements for stack testing, performance evaluations, and work practices for fugitive sources.

We estimate 12 regulated entities are currently subject to 40 CFR part 63, subpart AA and 11 regulated entities are currently subject to 40 CFR part 63, subpart BB and each will be subject to all applicable standards. The annual monitoring, reporting, and recordkeeping burden for these amendments to subpart AA and BB is estimated to be $224,000 per year (averaged over the first 3 years after the effective date of the standards). This includes 670 labor hours per year at a total labor cost of $55,000 per year, and total non-labor capital and operating and maintenance costs of $169,000 per year. This estimate includes performance tests, notifications, reporting and recordkeeping associated with the new requirements for emission points and associated control devices. The total burden to the federal government is estimated to be 330 hours per year at a total labor cost of $17,000 per year (averaged over the first 3 years after the effective date of the standard). Burden is defined at 5 CFR 1320.3(b).

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.

C. 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 impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. This rule will not impose any requirements on small entities because we do not project that any small entities will incur costs due to these rule amendments. We have therefore concluded that this action will have no net regulatory burden for all directly regulated small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

E. 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.

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

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. The tribal implications are primarily due to the close proximity of one facility to a tribe (the Shoshone-Bannock).

The EPA consulted with tribal officials under the EPA Policy on

Consultation and Coordination with Indian Tribes early in the process of developing this regulation to permit them to have meaningful and timely input into its development. The Agency provided an overview of the source categories and rulemaking process during a monthly teleconference with the National Tribal Air Association. Additionally, we provided targeted outreach, including a visit to the Shoshone-Bannock tribe and meeting with environmental leaders for the tribe.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action's health and risk assessments are contained in sections V.A. and VI.A.

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

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR part 51

This action involves technical standards. The EPA has decided to use analytical methods of the Association of Official Analytical Chemists (AOAC) and of the Association of Fertilizer and Phosphate Chemists (AFPC). The AOAC methods include: AOAC Official Method 957.02 Phosphorus (Total) in Fertilizers, Preparation of Sample Solution, AOAC Official Method 929.01 Sampling of Solid Fertilizers, AOAC Official Method 929.02 Preparation of Fertilizer Sample, AOAC Official Method 978.01 Phosphorous (Total) in Fertilizers, Automated Method, AOAC Official Method 969.02 Phosphorous (Total) in Fertilizers, Alkalimetric Quinolinium Molybdophosphate Method, AOAC Official Method 962.02 Phosphorous (Total) in Fertilizers, Gravimetric Quinolinium Molybdophosphate Method and Quinolinium Molybdophosphate Method 958.01 Phosphorous (Total) in Fertilizers, Spectrophotometric Molybdovanadophosphate Method. The AFPC methods for analysis of phosphate rock include: No. 1 Preparation of Sample, No. 3 Phosphorus-P_2O_5 or $Ca_3(PO_4)_2$, Method A—Volumetric Method, No. 3 Phosphorus-P_2O_5 or $Ca_3(PO_4)_2$, Method B—Gravimetric Quimociac Method, No. 3 Phosphorus-P_2O_5 or $Ca_3(PO_4)_2$, Method C—Spectrophotometric Method. The AFPC methods for analysis of phosphoric acid, superphosphate, triple superphosphate and ammonium phosphates include: No. 3 Total Phosphorus-P_2O_5, Method A-Volumetric Method, No. 3 Total Phosphorus-P_2O_5, Method B—Gravimetric Quimociac Method and No. 3 Total Phosphorus-P_2O_5, Method C—Spectrophotometric Method.

As discussed in the preamble of the proposal, under NESHAP subpart AA and NESHAP subpart BB, we conducted searches for EPA Methods 5, 13A, 13B, and 30B. The EPA conducted searches through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). We contacted voluntary consensus standards (VCS) organizations, and accessed and searched their databases. We did not identify any applicable VCS for EPA Methods 5, 13A, 13B, or 30B. Additional information for the VCS search and determinations can be found in the memorandum, ''Voluntary Consensus Standard Results for Phosphoric Acid Manufacturing and Phosphate Fertilizer Production RTR and Standards of Performance for Phosphate Processing,'' which is available in the docket for this action. The EPA solicited comments on VCS and invited the public to identify potentially applicable VCS; however, we did not receive comments regarding this aspect of NESHAP subpart AA and NESHAP subpart BB.

The EPA is incorporating, into NESHAP subpart AA and NESHAP subpart BB, the following guidance document: EPA–454/R–98–015, Office Of Air Quality Planning And Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, September 1997. This guidance document provides procedures for selecting, installing, setting up, adjusting, and operating a bag leak detection system; and also includes quality assurance procedures. This guidance document is readily accessible at *http://www.epa.gov/ttn/emc/cem.html*.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations because it increases the level of protection provided to human health or the environment. The results of this evaluation are contained in the memorandum titled ''Environmental Justice Review: Phosphate Fertilizer Production and Phosphoric Acid,'' which is available in Docket ID No. EPA–HQ–OAR–2012–0522, and are discussed in section VII.F of this preamble.

K. Congressional Review Act

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

List of Subjects

40 CFR Part 60

Environmental protection, Air pollution control, Fertilizers, Fluoride, Particulate matter, Phosphate, Reporting and recordkeeping requirements.

40 CFR Part 63

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

Dated: July 21, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, parts 60 and 63 of title 40, chapter I, of the Code of Federal Regulations are amended 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 T—Standards of Performance for the Phosphate Fertilizer Industry: Wet-Process Phosphoric Acid Plants

■ 2. Section 60.200 is amended by revising paragraph (a) to read as follows:

§ 60.200 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each wet-process phosphoric acid plant having a design capacity of more than 15 tons of equivalent P_2O_5 feed per calendar day.

* * * * *

■ 3. Section 60.201 is amended by revising paragraph (a) to read as follows:

§ 60.201 Definitions.

* * * * *

(a) *Wet-process phosphoric acid plant* means any facility manufacturing phosphoric acid by reacting phosphate rock and acid. A wet-process phosphoric acid plant includes: Reactors, filters, evaporators, and hot wells.

* * * * *

■ 4. Section 60.203 is amended by revising paragraph (c) and adding paragraph (d) to read as follows:

§ 60.203 Monitoring of operations.

* * * * *

(c) The owner or operator of any wet-process phosphoric acid plant subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the absorber. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(d) Any facility under § 60.200(a) that commences construction, modification or reconstruction after November 7, 2014 is subject to the requirements of this paragraph instead of the requirements in paragraph (c) of this section. If an absorber is used to comply with § 60.202, then the owner or operator shall continuously monitor pressure drop through the absorber and meet the requirements specified in paragraphs (d)(1) through (4) of this section.

(1) The owner or operator shall install, calibrate, maintain, and operate a continuous monitoring system (CMS) that continuously measures and permanently records the pressure at the gas stream inlet and outlet of the absorber. The pressure at the gas stream inlet of the absorber may be measured using amperage on the blower if a correlation between pressure and amperage is established.

(2) The CMS must have an accuracy of ±5 percent over the normal range measured or 0.12 kilopascals (0.5 inches of water column), whichever is greater.

(3) The owner or operator shall establish an allowable range for the pressure drop through the absorber. The allowable range is ±20 percent of the arithmetic average of the three test runs conducted during the performance test required in § 60.8. The Administrator retains the right to reduce the ±20 percent adjustment to the baseline average values of operating ranges in those instances where performance test results indicate that a source's level of emissions is near the value of an applicable emissions standard. However, the adjustment must not be reduced to less than ±10 percent under any instance.

(4) The owner or operator shall demonstrate continuous compliance by maintaining the daily average pressure drop through the absorber to within the allowable range established in paragraph (d)(3) of this section. The daily average pressure drop through the absorber for each operating day shall be calculated 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.

■ 5. Subpart T is amended by adding § 60.205 to read as follows:

§ 60.205 Recordkeeping.

Any facility under § 60.200(a) that commences construction, modification or reconstruction after November 7, 2014 is subject to the requirements of this section. You must maintain the records identified as specified in § 60.7(f) and in paragraphs (a) and (b) of this section. All records required by this subpart must be maintained on site for at least 5 years.

(a) *Records of the daily average pressure.* Records of the daily average pressure drop through the absorber.

(b) *Records of deviations.* A deviation is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (b)(1) and (2) of this section being met.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum pressure drop, or greater than the maximum pressure drop established in § 60.203(d)(3).

(2) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

Subpart U—Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants

■ 6. Section 60.210 is amended by revising paragraph (a) to read as follows:

§ 60.210 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each superphosphoric acid plant having a design capacity of more than 15 tons of equivalent P_2O_5 feed per calendar day.

* * * * *

■ 7. Section 60.211 is amended by revising paragraph (a) to read as follows:

§ 60.211 Definitions.

* * * * *

(a) *Superphosphoric acid plant* means any facility that concentrates wet-process phosphoric acid to 66 percent or greater P_2O_5 content by weight for eventual consumption as a fertilizer. A superphosphoric acid plant includes: evaporators, hot wells, acid sumps, oxidation reactors, and cooling tanks. An oxidation reactor includes any equipment or step that uses an oxidizing agent (*e.g.,* nitric acid, ammonium nitrate, or potassium permanganate) to treat superphosphoric acid.

* * * * *

■ 8. Section 60.213 is amended by revising paragraph (c) and adding paragraph (d) to read as follows:

§ 60.213 Monitoring of operations.

* * * * *

(c) Except as specified in paragraph (d) of this section, the owner or operator of any superphosphoric acid plant subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the absorber. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(d) Any affected facility as defined in § 60.210(a) that commences construction, modification or reconstruction after November 7, 2014 is subject to the requirements of this paragraph instead of the requirements in paragraph (c) of this section. If an absorber is used to comply with § 60.212, then the owner or operator shall continuously monitor pressure drop through the absorber and meet the requirements specified in paragraphs (d)(1) through (4) of this section.

(1) The owner or operator shall install, calibrate, maintain, and operate a continuous monitoring system (CMS) that continuously measures and permanently records the pressure at the gas stream inlet and outlet of the absorber. The pressure at the gas stream inlet of the absorber may be measured using amperage on the blower if a correlation between pressure and amperage is established.

(2) The CMS must have an accuracy of ±5 percent over the normal range measured or 0.12 kilopascals (0.5 inches of water column), whichever is greater.

(3) The owner or operator shall establish an allowable range for the pressure drop through the absorber. The allowable range is ±20 percent of the arithmetic average of the three test runs conducted during the performance test required in § 60.8. The Administrator retains the right to reduce the ±20 percent adjustment to the baseline average values of operating ranges in those instances where performance test results indicate that a source's level of emissions is near the value of an applicable emissions standard. However, the adjustment must not be reduced to less than ±10 percent under any instance.

(4) The owner or operator shall demonstrate continuous compliance by maintaining the daily average pressure drop through the absorber to within the allowable range established in paragraph (d)(3) of this section. The daily average pressure drop through the absorber for each operating day shall be calculated 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.

■ 9. Subpart U is amended by adding § 60.215 to read as follows:

§ 60.215 Recordkeeping.

An affected facility as defined in § 60.210(a) that commences construction, modification, or reconstruction after November 7, 2014 is subject to the requirements of this section. You must maintain the records identified as specified in § 60.7(f) and in paragraphs (a) and (b) of this section. All records required by this subpart must be maintained on site for at least 5 years.

(a) *Records of the daily average pressure.* Records of the daily average pressure drop through the absorber.

(b) *Records of deviations.* A deviation is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (b)(1) and (2) of this section being met.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum pressure drop, or greater than the maximum pressure drop established in § 60.213(d)(3).

(2) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

Subpart V—Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants

■ 10. Section 60.223 is amended by revising paragraph (c) and adding paragraph (d) to read as follows:

§ 60.223 Monitoring of operations.

* * * * *

(c) Except as specified in paragraph (d) of this section, the owner or operator of any granular diammonium phosphate plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the scrubbing system. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(d) Any affected facility as defined in § 60.220(a) that commences construction, modification, or reconstruction after November 7, 2014 is subject to the requirements of this paragraph instead of the requirements in paragraph (c) of this section. If an absorber is used to comply with § 60.222, then the owner or operator shall continuously monitor pressure drop through the absorber and meet the requirements specified in paragraphs (d)(1) through (4) of this section.

(1) The owner or operator shall install, calibrate, maintain, and operate a continuous monitoring system (CMS) that continuously measures and permanently records the pressure at the gas stream inlet and outlet of the absorber. The pressure at the gas stream inlet of the absorber may be measured using amperage on the blower if a correlation between pressure and amperage is established.

(2) The CMS must have an accuracy of ±5 percent over the normal range measured or 0.12 kilopascals (0.5 inches of water column), whichever is greater.

(3) The owner or operator shall establish an allowable range for the pressure drop through the absorber. The allowable range is ±20 percent of the arithmetic average of the three test runs conducted during the performance test required in § 60.8. The Administrator retains the right to reduce the ±20 percent adjustment to the baseline average values of operating ranges in those instances where performance test results indicate that a source's level of emissions is near the value of an applicable emissions standard. However, the adjustment must not be reduced to less than ±10 percent under any instance.

(4) The owner or operator shall demonstrate continuous compliance by maintaining the daily average pressure drop through the absorber to within the allowable range established in paragraph (d)(3) of this section. The daily average pressure drop through the absorber for each operating day shall be calculated 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.

■ 11. Section 60.224 is amended by revising paragraph (b)(3)(ii) to read as follows:

§ 60.224 Test methods and procedures.

* * * * *

(b) * * *

(3) * * *

(ii) The Association of Official Analytical Chemists (AOAC) Method 9 (incorporated by reference—see § 60.17) shall be used to determine the P_2O_5 content (R_p) of the feed.

■ 12. Subpart V is amended by adding § 60.225 to read as follows:

§ 60.225 Recordkeeping.

An affected facility as defined in § 60.220(a) that commences construction, modification, or reconstruction after November 7, 2014 is subject to the requirements of this section. You must maintain the records identified as specified in § 60.7(f) and in paragraphs (a) and (b) of this section. All records required by this subpart must be maintained on site for at least 5 years.

(a) Records of the daily average pressure drop through the absorber.

(b) Records of deviations. A deviation is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (b)(1) and (2) of this section being met.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum pressure drop, or greater than the maximum pressure drop established in § 60.223(d)(3).

(2) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

Subpart W—Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants

■ 13. Section 60.230 is amended by revising paragraph (a) to read as follows:

§ 60.230 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each triple superphosphate plant having a design capacity of more than 15 tons of equivalent P_2O_5 feed per calendar day. For the purpose of this subpart, the affected facility includes any combination of: mixers, curing belts (dens), reactors, granulators, dryers, coolers, screens, mills, and facilities that store run-of-pile triple superphosphate.

* * * * *

■ 14. Section 60.233 is revised to read as follows:

§ 60.233 Monitoring of operations.

(a) The owner or operator of any triple superphosphate plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a flow monitoring device that can be used to determine the mass flow of phosphorus-bearing feed material to the process. The flow monitoring device shall have an accuracy of ±5 percent over its operating range.

(b) The owner or operator of any triple superphosphate plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in Mg/hr of phosphorus-bearing feed using a flow monitoring device meeting the requirements of paragraph (a) of this section and then by proceeding according to § 60.234(b)(3).

(c) Except as specified in paragraph (d) of this section, the owner or operator of any triple superphosphate plant subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device that continuously measures and permanently records the total pressure drop across the absorber. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(d) Any facility under § 60.230(a) that commences construction, modification, or reconstruction after November 7, 2014 is subject to the requirements of this paragraph instead of the requirements in paragraph (c) of this section. If an absorber is used to comply with § 60.232, then the owner or operator shall continuously monitor pressure drop through the absorber and meet the requirements specified in paragraphs (d)(1) through (4) of this section.

(1) The owner or operator shall install, calibrate, maintain, and operate a continuous monitoring system (CMS) that continuously measures and permanently records the pressure at the gas stream inlet and outlet of the absorber. The pressure at the gas stream inlet of the absorber may be measured using amperage on the blower if a correlation between pressure and amperage is established.

(2) The CMS must have an accuracy of ±5 percent over the normal range measured or 0.12 kilopascals (0.5 inches of water column), whichever is greater.

(3) The owner or operator shall establish an allowable range for the pressure drop through the absorber. The allowable range is ±20 percent of the arithmetic average of the three test runs conducted during the performance test required in § 60.8. The Administrator retains the right to reduce the ±20 percent adjustment to the baseline average values of operating ranges in those instances where performance test results indicate that a source's level of emissions is near the value of an applicable emissions standard. However, the adjustment must not be reduced to less than ±10 percent under any instance.

(4) The owner or operator shall demonstrate continuous compliance by maintaining the daily average pressure drop through the absorber to within the allowable range established in paragraph (d)(3) of this section. The daily average pressure drop through the absorber for each operating day shall be calculated 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.

■ 15. Subpart W is amended by adding § 60.235 to read as follows:

§ 60.235 Recordkeeping.

Any facility under § 60.230(a) that commences construction, modification, or reconstruction after November 7, 2014 is subject to the requirements of this section. You must maintain the records identified as specified in § 60.7(f) and in paragraphs (a) and (b) of this section. All records required by this subpart must be maintained onsite for at least 5 years.

(a) Records of the daily average pressure drop through the absorber.

(b) Records of deviations. A deviation is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (b)(1) and (2) of this section being met.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum pressure drop, or greater than the maximum pressure drop established in § 60.233(d)(3).

(2) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

Subpart X—Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities

■ 16. Section 60.243 is amended by revising paragraph (c) and adding (e) to read as follows:

§ 60.243 Monitoring of operations.

* * * * *

(c) Except as specified in paragraph (e) of this section, the owner or operator of any granular triple superphosphate storage facility subject to the provisions of this subpart shall install, calibrate, maintain, and operate a monitoring device that continuously measures and permanently records the total pressure drop across any absorber. The monitoring device shall have an accuracy of ±5 percent over its operating range.

* * * * *

(e) Any facility under § 60.240(a) that commences construction, modification, or reconstruction after November 7, 2014 is subject to the requirements of this paragraph instead of the requirements in paragraph (c) of this section. If an absorber is used to comply with § 60.232, then the owner or operator shall continuously monitor pressure drop through the absorber and meet the requirements specified in paragraphs (e)(1) through (4) of this section.

(1) The owner or operator shall install, calibrate, maintain, and operate a continuous monitoring system (CMS) that continuously measures and permanently records the pressure at the gas stream inlet and outlet of the absorber. The pressure at the gas stream inlet of the absorber may be measured using amperage on the blower if a correlation between pressure and amperage is established.

(2) The CMS must have an accuracy of ±5 percent over the normal range measured or 0.12 kilopascals (0.5 inches of water column), whichever is greater.

(3) The owner or operator shall establish an allowable range for the

pressure drop through the absorber. The allowable range is ±20 percent of the arithmetic average of the three test runs conducted during the performance test required in § 60.8. The Administrator retains the right to reduce the ±20 percent adjustment to the baseline average values of operating ranges in those instances where performance test results indicate that a source's level of emissions is near the value of an applicable emissions standard. However, the adjustment must not be reduced to less than ±10 percent under any instance.

(4) The owner or operator shall demonstrate continuous compliance by maintaining the daily average pressure drop through the absorber to within the allowable range established in paragraph (e)(3) of this section. The daily average pressure drop through the absorber for each operating day shall be calculated 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.

■ 17. Subpart X is amended by adding § 60.245 to read as follows:

§ 60.245 Recordkeeping.

Any facility under § 60.240(a) that commences construction, modification, or reconstruction after November 7, 2014 is subject to the requirements of this section. You must maintain the records identified as specified in § 60.7(f) and in paragraphs (a) and (b) of this section. All records required by this subpart must be maintained onsite for at least 5 years.

(a) Records of the daily average pressure drop through the absorber.

(b) Records of deviations. A deviation is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (b)(1) and (2) of this section being met.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum pressure drop, or greater than the maximum pressure drop established in § 60.243(e)(3).

(2) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 18. The authority citation for part 63 continues to read as follows:

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

Subpart A—General Provisions

■ 19. Section 63.14 is amended by revising paragraphs (b), (c)(1) through (7), and (l)(2) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) The Association of Florida Phosphate Chemists, P.O. Box 1645, Bartow, Florida 33830.

(1) Book of Methods Used and Adopted By The Association of Florida Phosphate Chemists, Seventh Edition 1991:

(i) Section IX, Methods of Analysis for Phosphate Rock, No. 1 Preparation of Sample, IBR approved for § 63.606(f), § 63.626(f).

(ii) Section IX, Methods of Analysis for Phosphate Rock, No. 3 Phosphorus-P2O5 or Ca3(PO4)2, Method A—Volumetric Method, IBR approved for § 63.606(f), § 63.626(f).

(iii) Section IX, Methods of Analysis for Phosphate Rock, No. 3 Phosphorus-P2O5 or Ca3(PO4)2, Method B—Gravimetric Quimociac Method, IBR approved for § 63.606(f), § 63.626(f).

(iv) Section IX, Methods of Analysis For Phosphate Rock, No. 3 Phosphorus-P2O5 or Ca3(PO4)2, Method C—Spectrophotometric Method, IBR approved for § 63.606(f), § 63.626(f).

(v) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P2O5, Method A—Volumetric Method, IBR approved for § 63.606(f), § 63.626(f), and (g).

(vi) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P2O5, Method B—Gravimetric Quimociac Method, IBR approved for § 63.606(f), § 63.626(f), and (g).

(vii) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P2O5, Method C—Spectrophotometric Method, IBR approved for § 63.606(f), § 63.626(f), and (g).

(2) [Reserved]

(c) * * *

(1) AOAC Official Method 929.01 Sampling of Solid Fertilizers, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(2) AOAC Official Method 929.02 Preparation of Fertilizer Sample, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(3) AOAC Official Method 957.02 Phosphorus (Total) in Fertilizers, Preparation of Sample Solution, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(4) AOAC Official Method 958.01 Phosphorus (Total) in Fertilizers, Spectrophotometric Molybdovanadophosphate Method, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(5) AOAC Official Method 962.02 Phosphorus (Total) in Fertilizers, Gravimetric Quinolinium Molybdophosphate Method, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(6) AOAC Official Method 969.02 Phosphorus (Total) in Fertilizers, Alkalimetric Quinolinium Molybdophosphate Method, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(7) AOAC Official Method 978.01 Phosphorus (Total) in Fertilizers, Automated Method, Sixteenth edition, 1995, IBR approved for § 63.626(g).

* * * * *

(l) * * *

(2) EPA–454/R–98–015, Office Of Air Quality Planning And Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, September 1997, IBR approved for §§ 63.548(e), 63.606(m), 63.607(b), 63.626(h), 63.627(b), 63.7525(j), and 63.11224(f).

* * * * *

■ 20. Part 63 is amended by revising subpart AA to read as follows:

Subpart AA—National Emission Standards for Hazardous Air Pollutants from Phosphoric Acid Manufacturing Plants

§ 63.600 Applicability.

(a) Except as provided in paragraphs (c) and (d) of this section, you are subject to the requirements of this subpart if you own or operate a phosphoric acid manufacturing plant that is a major source as defined in § 63.2. You must comply with the emission limitations, work practice standards, and operating parameter requirements specified in this subpart at all times.

(b) The requirements of this subpart apply to emissions of hazardous air pollutants (HAP) emitted from the following affected sources at a phosphoric acid manufacturing plant:

(1) Each wet-process phosphoric acid process line.

(2) Each evaporative cooling tower.

(3) Each phosphate rock dryer.

(4) Each phosphate rock calciner.

(5) Each superphosphoric acid process line.

(6) Each purified phosphoric acid process line.

(7) Each gypsum dewatering stack.

(8) Each cooling pond.

(c) The requirements of this subpart do not apply to a phosphoric acid manufacturing plant that is an area source as defined in § 63.2.

(d) The provisions of this subpart do not apply to research and development facilities as defined in § 63.601.

§ 63.601 Definitions.

Terms used in this subpart are defined in § 63.2 of the Clean Air Act and in this section as follows:

Active gypsum dewatering stack means a gypsum dewatering stack that is currently receiving gypsum, received gypsum within the last year, or is part of the facility's water management system. A gypsum dewatering stack that is considered closed by a state authority is not considered an active gypsum dewatering stack.

Breakthrough means the point in time when the level of mercury detected at the outlet of an adsorber system is 90 percent of the highest concentration allowed to be discharged consistent with the applicable emission limit.

Cooling pond means a natural or artificial open reservoir that is primarily used to collect and cool water that comes into direct contact with raw materials, intermediate products, by-products, waste products, or finished products from a phosphoric acid manufacturing plant. The water in the cooling pond is often used at phosphoric acid manufacturing plants as filter wash water, absorber water for air pollution control absorbers, and/or to transport phosphogypsum as slurry to a gypsum dewatering stack(s).

Equivalent P_2O_5 feed means the quantity of phosphorus, expressed as phosphorus pentoxide (P_2O_5), fed to the process.

Evaporative cooling tower means an open-water, re-circulating device that uses fans or natural draft to draw or force ambient air through the device to remove heat from process water by direct contact.

Exceedance means a departure from an indicator range established for monitoring under this subpart, consistent with any averaging period specified for averaging the results of the monitoring.

Existing source depends on the date that construction or reconstruction of an affected source commenced. A wet-process phosphoric acid process line, superphosphoric acid process line, phosphate rock dryer, phosphate rock calciner, evaporative cooling tower, or purified acid process line is an existing source if construction or reconstruction of the affected source commenced on or before December 27, 1996. A gypsum dewatering stack or cooling pond is an existing source if it meets one of two criteria:

(1) It was constructed or reconstructed on or before August 19, 2015; or

(2) It was constructed or reconstructed after August 19, 2015 and it was not required to obtain a permit by a state authority for the construction or reconstruction.

Gypsum dewatering stack means any defined geographic area associated with a phosphoric acid manufacturing plant in which gypsum is disposed of or stored, other than within a fully enclosed building, container, or tank.

Gypsum dewatering stack system means the gypsum dewatering stack, together with all pumps, piping, ditches, drainage conveyances, water control structures, collection pools, cooling ponds, surge ponds, auxiliary holding ponds, regional holding ponds and any other collection or conveyance system associated with the transport of gypsum from the plant to the gypsum dewatering stack, its management at the gypsum dewatering stack, and the process wastewater return to the phosphoric acid production or other process.

HAP metals mean those metals and their compounds (in particulate or volatile form) that are included on the list of hazardous air pollutants in section 112 of the Clean Air Act. HAP metals include, but are not limited to: Antimony, arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium expressed as particulate matter as measured by the methods and procedures in this subpart or an approved alternative method. For the purposes of this subpart, HAP metals (except mercury) are expressed as particulate matter as measured by Method 5 at 40 CFR part 60, appendix A–3.

New source depends on the date that construction or reconstruction of an affected source commences. A wet-process phosphoric acid process line, superphosphoric acid process line, phosphate rock dryer, phosphate rock calciner, evaporative cooling tower, or purified acid process line is a new source if construction or reconstruction of the affected source commenced after December 27, 1996. A gypsum dewatering stack or cooling pond is a new source if it meets two criteria:

(1) It was constructed or reconstructed after August 19, 2015; and

(2) It was required to obtain a permit by a state authority for the construction or reconstruction.

Oxidation reactor means any equipment or step that uses an oxidizing agent (*e.g.,* nitric acid, ammonium nitrate, or potassium permanganate) to treat superphosphoric acid.

Phosphate rock calciner means the equipment used to remove moisture and organic matter from phosphate rock through direct or indirect heating.

Phosphate rock dryer means the equipment used to reduce the moisture content of phosphate rock through direct or indirect heating.

Phosphate rock feed means all material entering any phosphate rock dryer or phosphate rock calciner including moisture and extraneous material as well as the following ore materials: Fluorapatite, hydroxylapatite, chlorapatite, and carbonateapatite.

Purified phosphoric acid process line means any process line that uses a HAP as a solvent in the separation of impurities from the product acid for the purposes of rendering that product suitable for industrial, manufacturing, or food grade uses. A purified phosphoric acid process line includes:

solvent extraction process equipment, solvent stripping and recovery equipment, seal tanks, carbon treatment equipment, cooling towers, storage tanks, pumps, and process piping.

Raffinate stream means the aqueous stream containing the impurities that are removed during the purification of wet-process phosphoric acid using solvent extraction.

Research and development facility means research or laboratory operations whose primary purpose is to conduct research and development into new processes and products, where the operations are under the close supervision of technically trained personnel, and where the facility is not engaged in the manufacture of products for commercial sale in commerce or other off-site distribution, except in a de minimis manner.

Rim ditch (cell) building technique means a gypsum dewatering stack construction technique that utilizes inner and outer dikes to direct gypsum slurry flow around the perimeter of the stack before directing the flow and allowing settling of finer materials into the settling compartment. For the purpose of this definition, the rim ditch (cell) building technique includes the compartment startup phase when gypsum is deposited directly into the settling compartment in preparation for ditch construction as well as the step-in or terminal phases when most solids must be directed to the settling compartment prior to stack closure. Decant return ditches are not rim ditches.

Shutdown commences when feed materials cease to be added to an affected source and ends when the affected source is deactivated, regardless of whether feed material is present in the affected source.

Startup commences when any feed material is first introduced into an affected source and ends when feed material is fully loaded into the affected source.

Superphosphoric acid process line means any process line that concentrates wet-process phosphoric acid to 66 percent or greater P_2O_5 content by weight. A superphosphoric acid process line includes: evaporators, hot wells, acid sumps, oxidation reactors, and cooling tanks.

Total fluorides means elemental fluorine and all fluoride compounds, including the HAP HF, as measured by reference methods specified in 40 CFR part 60, appendix A, Method 13 A or B, or by equivalent or alternative methods approved by the Administrator pursuant to § 63.7(f).

Wet-process phosphoric acid process line means any process line manufacturing phosphoric acid by reacting phosphate rock and acid. A wet-process phosphoric acid process line includes: reactors, filters, evaporators, and hot wells.

§ 63.602 Standards and compliance dates.

(a) On and after the dates specified in paragraphs (a)(1) through (6) of this section, for each wet-process phosphoric acid process line, superphosphoric acid process line, phosphate rock dryer, and phosphate rock calciner, you must comply with the emission limits as specified in paragraphs (a)(1) through (6) of this section. If a process line contains more than one emission point, you must sum the emissions from all emission points in a process line to determine compliance with the specified emission limits.

(1) For each existing wet-process phosphoric acid process line, superphosphoric acid process line, and phosphate rock dryer that commenced construction or reconstruction on or before December 27, 1996, you must comply with the emission limits specified in Table 1 to this subpart beginning on June 10, 2002.

(2) For each existing phosphate rock calciner that commenced construction or reconstruction on or before December 27, 1996, you must comply with the emission limits as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) You must comply with the total particulate emission limit specified in Table 1 to this subpart beginning on June 10, 2002.

(ii) You must comply with the mercury emission limit specified in Table 1 to this subpart beginning on August 19, 2015.

(iii) You must comply with the total fluorides emission limit specified in Table 1 to this subpart beginning on August 19, 2015.

(3) For each new wet-process phosphoric acid process line, superphosphoric acid process line, and phosphate rock dryer that commences construction or reconstruction after December 27, 1996 and on or before August 19, 2015, you must comply with the emission limits specified in Table 2 to this subpart beginning on June 10, 1999 or at startup, whichever is later.

(4) For each new wet-process phosphoric acid process line, superphosphoric acid process line, and phosphate rock dryer that commences construction or reconstruction after August 19, 2015, you must comply with the emission limits specified in Table 2 to this subpart immediately upon startup.

(5) For each new phosphate rock calciner that commences construction or reconstruction after December 27, 1996 and on or before August 19, 2015, you must comply with the emission limits as specified in paragraphs (a)(5)(i) through (iii) of this section.

(i) You must comply with the total particulate emission limit specified in Table 2 to this subpart beginning on June 10, 1999 or at startup, whichever is later.

(ii) You must comply with the mercury emission limit specified in Table 2 to this subpart beginning on August 19, 2015, or upon startup, whichever is later.

(iii) You must comply with the total fluorides emission limit specified in Table 2 to this subpart beginning on August 19, 2015, or upon startup, whichever is later.

(6) For each new phosphate rock calciner that commences construction or reconstruction after August 19, 2015, you must comply with the emission limits specified in Table 2 to this subpart immediately upon startup.

(b) For each existing purified phosphoric acid process line that commenced construction or reconstruction on or before December 27, 1996, you must comply with the provisions of subpart H of this part and paragraphs (b)(1) through (3) of this section beginning on June 10, 2002. For each new purified phosphoric acid process line that commences construction or reconstruction after December 27, 1996, you must comply with the provisions of subpart H of this part and paragraphs (b)(1) through (3) of this section beginning on June 10, 1999 or at startup, whichever is later.

(1) Maintain a 30-day rolling average of daily concentration measurements of methyl isobutyl ketone equal to or below 20 parts per million by weight (ppmw) for each product acid stream.

(2) Maintain a 30-day rolling average of daily concentration measurements of methyl isobutyl ketone equal to or below 30 ppmw for each raffinate stream.

(3) Maintain the daily average temperature of the exit gas stream from the chiller stack below 50 degrees Fahrenheit.

(c) Beginning on June 10, 2002, you must not introduce into an existing evaporative cooling tower that commenced construction or reconstruction on or before December 27, 1996, any liquid effluent from any absorber installed to control emissions from process equipment. Beginning on June 10, 1999 or at startup, whichever is later, you must not introduce into a new evaporative cooling tower that commences construction or reconstruction after December 27, 1996, any liquid effluent from any absorber installed to control emissions from process equipment.

(d) For each gypsum dewatering stack system, you must prepare, and operate in accordance with, a gypsum dewatering stack and cooling pond management plan that contains the information specified in paragraph (e) of this section beginning on August 19, 2016.

(e) The gypsum dewatering stack and cooling pond management plan must include the information specified in paragraphs (e)(1) through (3) of this section. You must submit the gypsum dewatering stack and cooling pond management plan for approval to the Administrator as specified in paragraph (e)(4) of this section.

(1) Location (including latitude and longitude of centroid in decimal degrees to four decimal places) of each gypsum dewatering stack and each cooling pond in the gypsum dewatering stack system.

(2) Permitted maximum footprint acreage of each gypsum dewatering stack and each cooling pond in the gypsum dewatering stack system.

(3) Control measures that you use to minimize fugitive hydrogen fluoride emissions from the gypsum dewatering stack system. If you operate one or more active gypsum dewatering stacks or cooling ponds that are considered new sources as defined in § 63.601, then you must use, and include in the management plan, at least two of the control measures listed in paragraphs (e)(3)(i) through (vii) of this section for your gypsum dewatering stack system. If you only operate active gypsum dewatering stacks and cooling ponds that are considered existing sources as defined in § 63.601, then you must use, and include in the management plan, at least one of the control measures listed in paragraphs (e)(3)(i) through (vii) of this section for your gypsum dewatering stack system.

(i) For at least one cooling pond that is considered part of your gypsum dewatering stack system, you may choose to submerge the discharge pipe to a level below the surface of the cooling pond.

(ii) For at least one cooling pond that is considered part of your gypsum dewatering stack system, you may choose to use lime (or any other caustic substance) to raise the pH of the liquid (*e.g.,* the condensed vapors from the flash cooler and evaporators, and scrubbing liquid) discharged into the cooling pond. If you choose this control measure, then you must include in the plan the method used to raise the pH of the liquid discharged into the cooling pond, the target pH value (of the liquid discharged into the cooling pond) expected to be achieved by using the method, and the analyses used to determine and support the raise in pH.

(iii) For all cooling ponds that are considered part of your gypsum dewatering stack system, you may choose to reduce the total cooling pond surface area based on a facility specific evaluation plan. If you choose this control measure, then you must include in the facility specific evaluation plan certified by an independent licensed professional engineer or similarly qualified individual. You must also include in the plan the method used to reduce total cooling pond footprint, the analyses used to determine and support the reduction in the total cooling pond surface area, and the amount of total cooling pond surface area that was reduced due to the facility specific evaluation plan.

(iv) For at least one gypsum dewatering stack that is considered part of your gypsum dewatering stack system, you may choose to minimize the surface area of the gypsum pond associated with the active gypsum dewatering stack by using a rim ditch (cell) building technique or other building technique.

(v) For at least one gypsum dewatering stack that is considered part of your gypsum dewatering stack system, you may choose to apply slaked lime to the active gypsum dewatering stack surfaces. If you choose this control measure, then you must include in the plan the method used to determine the specific locations slaked lime is applied. The plan must also include the methods used to determine the quantity of, and when to apply, slaked lime (*e.g.,* slaked lime may be applied to achieve a state ambient air standard for fluorides, measured as hydrogen fluoride).

(vi) For at least one gypsum dewatering stack that is considered part of your gypsum dewatering stack system, you may choose to apply soil caps and vegetation, or a synthetic cover, to a portion of side slopes of the active gypsum dewatering stack. If you choose this control measure, then you must include in the plan the method used to determine the specific locations of soil caps and vegetation, or synthetic cover; and specify the acreage and locations where soil caps and vegetation, or synthetic cover, is applied. The plan must also include a schedule describing when soil caps and vegetation, or synthetic cover, is to be applied.

(vii) For all gypsum dewatering stacks that are considered part of your gypsum dewatering stack system, you may choose to establish closure requirements that at a minimum, contain requirements for the specified items in paragraphs (e)(3)(vii)(A) and (B) of this section.

(A) A specific trigger mechanism for when you must begin the closure process on the gypsum dewatering stack; and

(B) A requirement to install a final cover. For purposes of this paragraph, final cover means the materials used to cover the top and sides of a gypsum dewatering stack upon closure.

(4) You must submit your plan for approval to the Administrator at least 6 months prior to the compliance date specified in § 63.602(d), or with the permit application for modification, construction, or reconstruction. The plan must include details on how you will implement and show compliance with the control technique(s) that you have selected to use. The Administrator will approve or disapprove your plan within 90 days after receipt of the plan. To change any of the information submitted in the plan, you must submit a revised plan 60 days before the planned change is to be implemented in order to allow time for review and approval by the Administrator before the change is implemented.

(f) Beginning on August 19, 2015, during periods of startup and shutdown (as defined in § 63.601), you must comply with the work practice specified in this paragraph in lieu of the emission limits specified in paragraph (a) of this section. During periods of startup and shutdown, you must operate any control device(s) being used at the affected source, monitor the operating parameters specified in Table 3 of this subpart, and comply with the operating limits specified in Table 4 of this subpart.

§ 63.603 [Reserved]

§ 63.604 [Reserved]

§ 63.605 Operating and monitoring requirements.

(a) For each wet-process phosphoric acid process line or superphosphoric acid process line subject to the provisions of this subpart, you must comply with the monitoring requirements specified in paragraphs (a)(1) and (2) of this section.

(1) Install, calibrate, maintain, and operate a continuous monitoring system (CMS) according to your site-specific monitoring plan specified in § 63.608(c). The CMS must have an accuracy of ±5 percent over its operating range and

must determine and permanently record the mass flow of phosphorus-bearing material fed to the process.

(2) Maintain a daily record of equivalent P_2O_5 feed. Calculate the equivalent P_2O_5 feed by determining the total mass rate, in metric ton/hour of phosphorus bearing feed, using the monitoring system specified in paragraph (a)(1) of this section and the procedures specified in § 63.606(f)(3).

(b) For each phosphate rock dryer or phosphate rock calciner subject to the provisions of this subpart, you must comply with the monitoring requirements specified in paragraphs (b)(1) and (2) of this section.

(1) Install, calibrate, maintain, and operate a CMS according to your site-specific monitoring plan specified in § 63.608(c). The CMS must have an accuracy of ±5 percent over its operating range and must determine and permanently record either:

(i) The mass flow of phosphorus-bearing feed material to the phosphate rock dryer or calciner, or

(ii) The mass flow of product from the phosphate rock dryer or calciner.

(2) Maintain the records specified in paragraphs (b)(2)(i) and (ii) of this section.

(i) If you monitor the mass flow of phosphorus-bearing feed material to the phosphate rock dryer or calciner as specified in paragraph (b)(1)(i) of this section, maintain a daily record of phosphate rock feed by determining the total mass rate in metric tons/hour of phosphorus-bearing feed.

(ii) If you monitor the mass flow of product from the phosphate rock dryer or calciner as specified in paragraph (b)(1)(ii) of this section, maintain a daily record of product by determining the total mass rate in metric ton/hour of product.

(c) For each purified phosphoric acid process line, you must comply with the monitoring requirements specified in paragraphs (c)(1) and (2) of this section.

(1) Install, calibrate, maintain, and operate a CMS according to your site-specific monitoring plan specified in § 63.608(c). The CMS must continuously measure and permanently record the stack gas exit temperature for each chiller stack.

(2) Measure and record the concentration of methyl isobutyl ketone in each product acid stream and each raffinate stream once each day.

(d) If you use a control device(s) to comply with the emission limits specified in Table 1 or 2 of this subpart, you must install a continuous parameter monitoring system (CPMS) and comply with the requirements specified in paragraphs (d)(1) through (5) of this section.

(1) You must monitor the operating parameter(s) applicable to the control device that you use as specified in Table 3 to this subpart and establish the applicable limit or range for the operating parameter limit as specified in paragraphs (d)(1)(i) and (ii) of this section, as applicable.

(i) Except as specified in paragraph (d)(1)(ii) of this section, determine the value(s) as the arithmetic average of operating parameter measurements recorded during the three test runs conducted for the most recent performance test.

(ii) If you use an absorber or a wet electrostatic precipitator to comply with the emission limits in Table 1 or 2 to this subpart and you monitor pressure drop across the absorber or secondary voltage for a wet electrostatic precipitator, you must establish allowable ranges using the methodology specified in paragraphs (d)(1)(ii)(A) and (B) of this section.

(A) The allowable range for the daily averages of the pressure drop across an absorber, or secondary voltage for a wet electrostatic precipitator, is ±20 percent of the baseline average value determined in paragraph (d)(1)(i) of this section. The Administrator retains the right to reduce the ±20 percent adjustment to the baseline average values of operating ranges in those instances where performance test results indicate that a source's level of emissions is near the value of an applicable emissions standard. However, the adjustment must not be reduced to less than ±10 percent under any instance.

(B) As an alternative to paragraph (d)(1)(ii)(A) of this section, you may establish allowable ranges for the daily averages of the pressure drop across an absorber, or secondary voltage for an electrostatic precipitator, for the purpose of assuring compliance with this subpart using the procedures described in this paragraph. You must establish the allowable ranges based on the baseline average values recorded during previous performance tests, or the results of performance tests conducted specifically for the purposes of this paragraph. You must conduct all performance tests using the methods specified in § 63.606. You must certify that the control devices and processes have not been modified since the date of the performance test from which you obtained the data used to establish the allowable ranges. When a source using the methodology of this paragraph is retested, you must determine new allowable ranges of baseline average values unless the retest indicates no change in the operating parameters outside the previously established ranges.

(2) You must monitor, record, and demonstrate continuous compliance using the minimum frequencies specified in Table 4 to this subpart.

(3) You must comply with the calibration and quality control requirements that are applicable to the operating parameter(s) you monitor as specified in Table 5 to this subpart.

(4) If you use a non-regenerative adsorption system to achieve the mercury emission limits specified in Table 1 or 2 to this subpart, you must comply with the requirements specified in paragraph (e) of this section.

(5) If you use a sorbent injection system to achieve the mercury emission limits specified in Table 1 or 2 to this subpart and you use a fabric filter to collect the associated particulate matter, the system must meet the requirements for fabric filters specified in paragraph (f) of this section.

(e) If you use a non-regenerative adsorption system to achieve the mercury emission limits specified in Table 1 or 2 to this subpart, you must comply with the requirements specified in paragraphs (e)(1) through (3) of this section.

(1) Determine the adsorber bed life (*i.e.,* the expected life of the sorbent in the adsorption system) using the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) If the adsorber bed is expected (designed) to have a life of less than 2 years, determine the outlet concentration of mercury on a quarterly basis until breakthrough occurs for the first three adsorber bed change-outs. The adsorber bed life shall equal the average length of time between each of the three change-outs.

(ii) If the adsorber bed is expected (designed) to have a life of 2 years or greater, determine the outlet concentration of mercury on a semi-annual basis until breakthrough occurs for the first two adsorber bed change-outs. The adsorber bed life must equal the average length of time between each of the two change-outs.

(iii) If more than one adsorber is operated in parallel, or there are several identical operating lines controlled by adsorbers, you may determine the adsorber bed life by measuring the outlet concentration of mercury from one of the adsorbers or adsorber systems rather than determining the bed life for each adsorber.

(iv) The adsorber or adsorber system you select for the adsorber bed life test must have the highest expected inlet gas mercury concentration and the highest operating rate of any adsorber in operation at the affected source. During the test to determine adsorber bed life, you must use the fuel that contains the highest level of mercury in any fuel-burning unit associated with the adsorption system being tested.

(2) You must replace the sorbent in each adsorber on or before the end of the adsorbent bed life, calculated in paragraph (e)(1) of this section.

(3) You must re-establish the adsorber bed life if the sorbent is replaced with a different brand or type, or if any process changes are made that would lead to a shorter bed lifetime.

(f) Beginning August 19, 2016, if you use a fabric filter system to comply with the emission limits specified in Table 1 or 2 to this subpart, then the fabric filter must be equipped with a bag leak detection system that is installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (f)(1) through (10) of this section.

(1) Install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute particulate matter loadings for each exhaust stack, roof vent, or compartment (*e.g.,* for a positive-pressure fabric filter) of the fabric filter.

(2) Use a bag leak detection system certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic feet) or less.

(3) Use a bag leak detection system equipped with a device to continuously record the output signal from the system sensor.

(4) Use a bag leak detection system equipped with a system that will trigger an alarm when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located such that the alert is observed readily by plant operating personnel.

(5) Install a bag leak detection system in each compartment or cell for positive-pressure fabric filter systems that do not duct all compartments or cells to a common stack. Install a bag leak detector downstream of the fabric filter if a negative-pressure or induced-air filter system is used. If multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

(6) Calibration of the bag leak detection system must, at a minimum, consist of establishing the baseline output level by adjusting the range and the averaging period of the device and establishing the alarm set points and the alarm delay time.

(7) After initial adjustment, you must not adjust the sensitivity or range, averaging period, alarm set points, or alarm delay time except as established in your site-specific monitoring plan required in § 63.608(c). In no event may the sensitivity be increased more than 100 percent or decreased by more than 50 percent over a 365-day period unless such adjustment follows a complete inspection of the fabric filter system that demonstrates that the system is in good operating condition.

(8) Operate and maintain each fabric filter and bag leak detection system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. If the alarm sounds more than 5 percent of the operating time during a 6-month period, it is considered an operating parameter exceedance. Calculate the alarm time (*i.e.,* time that the alarm sounds) as specified in paragraphs (f)(8)(i) through (iii) of this section.

(i) If inspection of the fabric filter demonstrates that corrective action is not required, the alarm duration is not counted in the alarm time calculation.

(ii) If corrective action is required, each alarm time is counted as a minimum of 1 hour.

(iii) If it takes longer than 1 hour to initiate corrective action, each alarm time is counted as the actual amount of time taken to initiate corrective action.

(9) If the alarm on a bag leak detection system is triggered, you must initiate procedures within 1 hour of an alarm to identify the cause of the alarm and then initiate corrective action, as specified in § 63.608(d)(2), no later than 48 hours after an alarm. Failure to take these actions within the prescribed time periods is considered a violation.

(10) Retain records of any bag leak detection system alarm, including the date, time, duration, and the percent of the total operating time during each 6-month period that the alarm sounds, with a brief explanation of the cause of the alarm, the corrective action taken, and the schedule and duration of the corrective action.

(g) If you choose to directly monitor mercury emissions instead of using CPMS as specified in paragraph (d) of this section, then you must install and operate a mercury CEMS in accordance with Performance Specification 12A of appendix B to part 60 of this chapter, or a sorbent trap-based integrated monitoring system in accordance with Performance Specification 12B of appendix B to part 60 of this chapter. You must continuously monitor mercury emissions as specified in paragraphs (g)(1) through (4) of this section.

(1) The span value for any mercury CEMS must include the intended upper limit of the mercury concentration measurement range during normal operation, which may be exceeded during other short-term conditions lasting less than 24 consecutive operating hours. However, the span should be at least equivalent to approximately two times the emissions standard. You may round the span value to the nearest multiple of 10 micrograms per cubic meter of total mercury.

(2) You must operate and maintain each mercury CEMS or sorbent trap-based integrated monitoring system according to the quality assurance requirements specified in Procedure 5 of appendix F to part 60 of this chapter.

(3) You must conduct relative accuracy testing of mercury monitoring systems, as specified in Performance Specification 12A, Performance Specification 12B, or Procedure 5 of appendix B to part 60 of this chapter, at normal operating conditions.

(4) If you use a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the exhaust gas flow rate to the atmosphere according to your site-specific monitoring plan specified in § 63.608(c).

§ 63.606 Performance tests and compliance provisions.

(a) You must conduct an initial performance test to demonstrate compliance with the applicable emission limits specified in Tables 1 and 2 to this subpart, within 180 days of the applicable compliance date specified in § 63.602.

(b) After you conduct the initial performance test specified in paragraph (a) of this section, you must conduct a performance test once per calendar year.

(c) For affected sources (as defined in § 63.600) that have not operated since the previous annual performance test was conducted and more than 1 year has passed since the previous performance test, you must conduct a performance test no later than 180 days after the re-start of the affected source according to the applicable provisions in § 63.7(a)(2).

(d)(1) You must conduct the performance tests specified in this section at representative (normal) conditions for the process. Representative (normal) conditions means those conditions that:

(i) Represent the range of combined process and control measure conditions under which the facility expects to operate (regardless of the frequency of the conditions); and

(ii) Are likely to most challenge the emissions control measures of the facility with regard to meeting the applicable emission standards, but without creating an unsafe condition. Operations during startup, shutdown, and malfunction do not constitute representative (normal) operating conditions for purposes of conducting a performance test.

(2) You must record the process information that is necessary to document the operating conditions during the test and include in such record an explanation to support that such conditions represent representative (normal) conditions. Upon request, you must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(e) In conducting all performance tests, you must use as reference methods and procedures the test methods in 40 CFR part 60, appendix A, or other methods and procedures as specified in this section, except as provided in § 63.7(f).

(f) You must determine compliance with the applicable total fluorides standards specified in Tables 1 and 2 to this subpart as specified in paragraphs (f)(1) through (3) of this section.

(1) Compute the emission rate (E) of total fluorides for each run using Equation AA–1:

$$E = \left(\sum_{i=1}^{N} C_i Q_i \right) / (PK) \qquad \text{(Eq. AA-1)}$$

Where:

E = Emission rate of total fluorides, gram/metric ton (pound/ton) of equivalent P_2O_5 feed.
C_i = Concentration of total fluorides from emission point ''i,'' milligram/dry standard cubic meter (milligram/dry standard cubic feet).
Q_i = Volumetric flow rate of effluent gas from emission point ''i,'' dry standard cubic meter/hour (dry standard cubic feet/hour).
N = Number of emission points associated with the affected facility.
P = Equivalent P_2O_5 feed rate, metric ton/hour (ton/hour).
K = Conversion factor, 1000 milligram/gram (453,600 milligram/pound).

(2) You must use Method 13A or 13B (40 CFR part 60, appendix A) to determine the total fluorides concentration (C_i) and the volumetric flow rate (Q_i) of the effluent gas at each emission point. The sampling time for each run at each emission point must be at least 60 minutes. The sampling volume for each run at each emission point must be at least 0.85 dscm (30 dscf). If Method 13B is used, the fusion of the filtered material described in Section 7.3.1.2 and the distillation of suitable aliquots of containers 1 and 2, described in section 7.3.3 and 7.3.4 in Method 13 A, may be omitted.

(3) Compute the equivalent P_2O_5 feed rate (P) using Equation AA–2:

$$P = M_p R_p \qquad \text{(Eq. AA-2)}$$

Where:

P = P_2O_5 feed rate, metric ton/hr (ton/hour).
M_p = Total mass flow rate of phosphorus-bearing feed, metric ton/hour (ton/hour).
R_p = P_2O_5 content, decimal fraction.

(i) Determine the mass flow rate (M_p) of the phosphorus-bearing feed using the measurement system described in § 63.605(a).

(ii) Determine the P_2O_5 content (R_p) of the feed using, as appropriate, the following methods specified in Methods Used and Adopted By The Association of Florida Phosphate Chemists (incorporated by reference, see § 63.14) where applicable:

(A) Section IX, Methods of Analysis for Phosphate Rock, No. 1 Preparation of Sample.

(B) Section IX, Methods of Analysis for Phosphate Rock, No. 3 Phosphorus-P_2O_5 or $Ca_3(PO_4)_2$, Method A—Volumetric Method.

(C) Section IX, Methods of Analysis for Phosphate Rock, No. 3 Phosphorus-P_2O_5 or $Ca_3(PO_4)_2$, Method B—Gravimetric Quimociac Method.

(D) Section IX, Methods of Analysis for Phosphate Rock, No. 3 Phosphorus-P_2O_5 or $Ca_3(PO_4)_2$, Method C—Spectrophotometric Method.

(E) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P_2O_5, Method A—Volumetric Method.

(F) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P_2O_5, Method B—Gravimetric Quimociac Method.

(G) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P_2O_5, Method C—Spectrophotometric Method.

(g) You must demonstrate compliance with the applicable particulate matter standards specified in Tables 1 and 2 to this subpart as specified in paragraphs (g)(1) through (3) of this section.

(1) Compute the emission rate (E) of particulate matter for each run using Equation AA–3:

$$E = (C\ Q) / (P\ K) \qquad \text{(Eq. AA-3)}$$

Where:

E = Emission rate of particulate matter, kilogram/megagram (pound/ton) of phosphate rock feed.
C = Concentration of particulate matter, gram/dry standard cubic meter (gram/dry standard cubic feet).
Q = Volumetric flow rate of effluent gas, dry standard cubic meter/hour (dry standard cubic feet/hour).
P = Phosphate rock feed rate, megagram/hour (ton/hour).
K = Conversion factor, 1000 grams/kilogram (453.6 grams/pound).

(2) Use Method 5 at 40 CFR part 60, appendix A–3 to determine the particulate matter concentration (C) and volumetric flow rate (Q) of the effluent gas. Except as specified in paragraph (h) of this section, the sampling time and

sample volume for each run must be at least 60 minutes and 0.85 dry standard cubic meter (30 dry standard cubic feet).

(3) Use the CMS described in § 63.605(b) to determine the phosphate rock feed rate (P) for each run.

(h) To demonstrate compliance with the particulate matter standards for phosphate rock calciners specified in Tables 1 and 2 to this subpart, you must use Method 5 at 40 CFR part 60, appendix A–3 to determine the particulate matter concentration. The sampling volume for each test run must be at least 1.70 dry standard cubic meter.

(i) To demonstrate compliance with the mercury emission standards for phosphate rock calciners specified in Tables 1 and 2 to this subpart, you must use Method 30B at 40 CFR part 60, appendix A–8 to determine the mercury concentration, unless you use a CEMS to demonstrate compliance. If you use a non-regenerative adsorber to control mercury emissions, you must use this test method to determine the expected bed life as specified in § 63.605(e)(1).

(j) If you choose to monitor the mass flow of product from the phosphate rock dryer or calciner as specified in § 63.605(b)(1)(ii), you must either:

(1) Simultaneously monitor the feed rate and output rate of the phosphate rock dryer or calciner during the performance test, or

(2) Monitor the output rate and the input and output moisture contents of the phosphate rock dryer or calciner during the performance test and calculate the corresponding phosphate rock dryer or calciner input rate.

(k) For sorbent injection systems, you must conduct the performance test at the outlet of the fabric filter used for sorbent collection. You must monitor and record operating parameter values for the fabric filter during the performance test. If the sorbent is replaced with a different brand or type of sorbent than was used during the performance test, you must conduct a new performance test.

(l) If you use a mercury CEMS as specified in § 63.605(g), or paragraph (i) of this section, you must demonstrate initial compliance based on the first 30 operating days during which you operate the affected source using a CEMS. You must obtain hourly mercury concentration and stack gas volumetric flow rate data.

(m) If you use a CMS, you must conduct a performance evaluation, as specified in § 63.8(e), in accordance with your site-specific monitoring plan in § 63.608(c). For fabric filters, you must conduct a performance evaluation of the bag leak detection system consistent with the guidance provided in Office Of Air Quality Planning And Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance (incorporated by reference, see § 63.14). You must record the sensitivity of the bag leak detection system to detecting changes in particulate matter emissions, range, averaging period, and alarm set points during the performance test.

§ 63.607 Notification, recordkeeping, and reporting requirements.

(a) You must comply with the notification requirements specified in § 63.9. During the most recent performance test, if you demonstrate compliance with the emission limit while operating your control device outside the previously established operating limit, you must establish a new operating limit based on that most recent performance test and notify the Administrator that the operating limit changed based on data collected during the most recent performance test. When a source is retested and the performance test results are submitted to the Administrator pursuant to paragraph (b)(1) of this section, § 63.7(g)(1), or § 63.10(d)(2), you must indicate whether the operating limit is based on the new performance test or the previously established limit. Upon establishment of a new operating limit, you must thereafter operate under the new operating limit. If the Administrator determines that you did not conduct the compliance test in accordance with the applicable requirements or that the operating limit established during the performance test does not correspond to representative (normal) conditions, you must conduct a new performance test and establish a new operating limit.

(b) You must comply with the reporting and recordkeeping requirements in § 63.10 as specified in paragraphs (b)(1) through (5) of this section.

(1) You must comply with the general recordkeeping requirements in § 63.10(b)(1).

(2) As required by § 63.10(d), you must report the results of the initial and subsequent performance tests as part of the notification of compliance status required in § 63.9(h). You must verify in the performance test reports that the operating limits for each process have not changed or provide documentation of revised operating limits established according to § 63.605, as applicable. In the notification of compliance status, you must also:

(i) Certify to the Administrator annually that you have complied with the evaporative cooling tower requirements specified in § 63.602(c).

(ii) Submit analyses and supporting documentation demonstrating conformance with the Office Of Air Quality Planning And Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance (incorporated by reference, see § 63.14) and specifications for bag leak detection systems as part of the notification of compliance status report.

(iii) Submit the gypsum dewatering stack and cooling pond management plan specified in § 63.602(e).

(iv) If you elect to demonstrate compliance by following the procedures in § 63.605(d)(1)(ii)(B), certify to the Administrator annually that the control devices and processes have not been modified since the date of the performance test from which you obtained the data used to establish the allowable ranges.

(v) Each time a gypsum dewatering stack is closed, certify to the Administrator within 90 days of closure, that the final cover of the closed gypsum dewatering stack is a drought resistant vegetative cover that includes a barrier soil layer that will sustain vegetation.

(3) As required by § 63.10(e)(3), you must submit an excess emissions report for any exceedance of an emission limit, work practice standard, or operating parameter limit if the total duration of the exceedances for the reporting period is 1 percent of the total operating time for the reporting period or greater. The report must contain the information specified in § 63.10 and paragraph (b)(4) of this section. When exceedances of an emission limit or operating parameter have not occurred, you must include such information in the report. You must submit the report semiannually and the report must be delivered or postmarked by the 30th day following the end of the calendar half. If you report exceedances, you must submit the excess emissions report quarterly until a request to reduce reporting frequency is approved as described in § 63.10(e)(3)(ii).

(4) In the event that an affected unit fails to meet an applicable standard, record and report the following information for each failure:

(i) The date, time and duration of the failure.

(ii) A list of the affected sources or equipment for which a failure occurred.

(iii) An estimate of the volume of each regulated pollutant emitted over any emission limit.

(iv) A description of the method used to estimate the emissions.

(v) A record of actions taken to minimize emissions in accordance with § 63.608(b), and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

(5) You must submit a summary report containing the information specified in § 63.10(e)(3)(vi). You must submit the summary report semiannually and the report must be delivered or postmarked by the 30th day following the end of the calendar half.

(c) Your records must be in a form suitable and readily available for expeditious review. You must keep each record for 5 years following the date of each recorded action. You must keep each record on site, or accessible from a central location by computer or other means that instantly provides access at the site, for at least 2 years after the date of each recorded action. You may keep the records off site for the remaining 3 years.

(d) In computing averages to determine compliance with this subpart, you must exclude the monitoring data specified in paragraphs (d)(1) and (2) of this section.

(1) Periods of non-operation of the process unit;

(2) Periods of no flow to a control device; and any monitoring data recorded during CEMS or continuous parameter monitoring system (CPMS) breakdowns, out-of-control periods, repairs, maintenance periods, instrument adjustments or checks to maintain precision and accuracy, calibration checks, and zero (low-level), mid-level (if applicable), and high-level adjustments.

(e) Within 60 days after the date of completing each performance test (as defined in § 63.2) required by this subpart, you must submit the results of the performance tests, including any associated fuel analyses, following the procedure specified in either paragraph (e)(1) or (2) of this section.

(1) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*http://cdx.epa.gov/epa_home.asp*). Performance test data must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, you may submit performance test data in an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site once the XML schema is available. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(2) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

(f) Within 60 days after the date of completing each continuous emissions monitoring system performance evaluation (as defined in § 63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (f)(1) or (2) of this section.

(1) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, you may submit performance evaluation data in an electronic file format consistent with the XML schema listed on the EPA's ERT Web site once the XML schema is available. If you claim that some of the performance evaluation information being transmitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic storage media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(2) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT Web site, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in § 63.13.

§ 63.608 General requirements and applicability of general provisions of this part.

(a) You must comply with the general provisions in subpart A of this part as specified in appendix A to this subpart.

(b) At all times, you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination by the Administrator of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c) For each CMS (including CEMS or CPMS) used to demonstrate compliance with any applicable emission limit or work practice, you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan according to the requirements specified in paragraphs (c)(1) through (3) of this section. You must submit the site-specific monitoring plan, if requested by the Administrator, at least 60 days before the initial performance evaluation of the CMS. The requirements of this paragraph also apply if a petition is made to the Administrator for alternative monitoring parameters under § 63.8(f).

(1) You must include the information specified in paragraphs (c)(1)(i) through (vi) of this section in the site-specific monitoring plan.

(i) Location of the CMS sampling probe or other interface. You must include a justification demonstrating that the sampling probe or other interface is at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.,* on or downstream of the last control device).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations).

(iv) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), (c)(4)(ii), and Table 4 to this subpart.

(v) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d)(1) and (2) and Table 5 to this subpart.

(vi) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1), and (e)(2)(i).

(2) You must include a schedule for conducting initial and subsequent performance evaluations in the site-specific monitoring plan.

(3) You must keep the site-specific monitoring plan on site for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If you revise the site-specific monitoring plan, you must keep previous (*i.e.,* superseded) versions of the plan on site to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. You must include the program of corrective action required under § 63.8(d)(2) in the plan.

(d) For each bag leak detection system installed to comply with the requirements specified in § 63.605(f), you must include the information specified in paragraphs (d)(1) and (2) of this section in the site-specific monitoring plan specified in paragraph (c) of this section.

(1) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations), including how the alarm set point will be established.

(2) A corrective action plan describing corrective actions to be taken and the timing of those actions when the bag leak detection alarm sounds. Corrective actions may include, but are not limited to, the actions specified in paragraphs (d)(2)(i) through (vi) of this section.

(i) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other conditions that may cause an increase in regulated material emissions.

(ii) Sealing off defective bags or filter media.

(iii) Replacing defective bags or filter media or otherwise repairing the control device.

(iv) Sealing off a defective fabric filter compartment.

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system.

(vi) Shutting down the process controlled by the fabric filter.

§ 63.609 [Reserved]

§ 63.610 Exemption from new source performance standards.

Any affected source subject to the provisions of this subpart is exempted from any otherwise applicable new source performance standard contained in 40 CFR part 60, subpart T, subpart U, or subpart NN. To be exempt, a source must have a current operating permit pursuant to title V of the Clean Air Act and the source must be in compliance with all requirements of this subpart. For each affected source, this exemption is effective upon the date that you demonstrate to the Administrator that the requirements of §§ 63.605 and 63.606 have been met.

§ 63.611 Implementation and enforcement.

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as the applicable state, local, or Tribal agency. If the U.S. EPA Administrator has delegated authority to a state, local, or Tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a state, local, or Tribal agency.

(b) The authorities specified in paragraphs (b)(1) through (5) of this section are retained by the Administrator of U.S. EPA and cannot be delegated to State, local, or Tribal agencies.

(1) Approval of alternatives to the requirements in §§ 63.600, 63.602, 63.605, and 63.610.

(2) Approval of requests under §§ 63.7(e)(2)(ii) and 63.7 (f) for alternative requirements or major changes to the test methods specified in this subpart, as defined in § 63.90.

(3) Approval of requests under § 63.8(f) for alternative requirements or major changes to the monitoring requirements specified in this subpart, as defined in § 63.90.

(4) Waiver or approval of requests under § 63.10(f) for alternative requirements or major changes to the recordkeeping and reporting requirements specified in this subpart, as defined in § 63.90.

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

TABLE 1 TO SUBPART AA OF PART 63—EXISTING SOURCE EMISSION LIMITS [a] [b]

For the following existing sources . . .	You must meet the emission limits for the specified pollutant . . .		
	Total fluorides	Total particulate	Mercury
Wet-Process Phosphoric Acid Line	0.020 lb/ton of equivalent P_2O_5 feed.		
Superphosphoric Acid Process Line [c].	0.010 lb/ton of equivalent P_2O_5 feed.		
Superphosphoric Acid Submerged Line with a Submerged Combustion Process.	0.20 lb/ton of equivalent P_2O_5 feed.		
Phosphate Rock Dryer		0.2150 lb/ton of phosphate rock feed.	
Phosphate Rock Calciner	9.0E–04 lb/ton of rock feed [d]	0.181 g/dscm	0.14 mg/dscm corrected to 3 percent oxygen [d]

[a] The existing source compliance date is June 10, 2002, except as noted.

[b] During periods of startup and shutdown, for emission limits stated in terms of pounds of pollutant per ton of feed, you are subject to the work practice standards specified in § 63.602(f).

[c] Beginning on August 19, 2016, you must include oxidation reactors in superphosphoric acid process lines when determining compliance with the total fluorides limit.

[d] Compliance date is August 19, 2015.

TABLE 2 TO SUBPART AA OF PART 63—NEW SOURCE EMISSION LIMITS [a] [b]

For the following new sources . . .	You must meet the emissions limits for the specified pollutant . . .		
	Total fluorides	Total particulate	Mercury
Wet-Process Phosphoric Acid Line	0.0135 lb/ton of equivalent P_2O_5 feed.		
Superphosphoric Acid Process Line [c].	0.00870 lb/ton of equivalent P_2O_5 feed.		
Phosphate Rock Dryer	....	0.060 lb/ton of phosphate rock feed.	
Phosphate Rock Calciner	9.0E–04 lb/ton of rock feed	0.092 g/dscm	0.014 mg/dscm corrected to 3 percent oxygen

[a] The new source compliance dates are based on date of construction or reconstruction as specified in § 63.602(a).

[b] During periods of startup and shutdown, for emission limits stated in terms of pounds of pollutant per ton of feed, you are subject to the work practice standards specified in § 63.602(f).

[c] Beginning on August 19, 2016, you must include oxidation reactors in superphosphoric acid process lines when determining compliance with the total fluorides limit.

TABLE 3 TO SUBPART AA OF PART 63—MONITORING EQUIPMENT OPERATING PARAMETERS

You must . . .	If . . .	And you must monitor . . .	And . . .
Absorbers (Wet Scrubbers)			
Install a continuous parameter monitoring system (CPMS) for liquid flow at the inlet of the absorber.	Your absorber is designed and operated with pressure drops of 5 inches of water column or more; and you choose to monitor only the influent liquid flow, rather than the liquid-to-gas ratio.	Influent liquid flow.	
Install CPMS for liquid and gas flow at the inlet of the absorber.	Your absorber is designed and operated with pressure drops of 5 inches of water column or less; or. Your absorber is designed and operated with pressure drops of 5 inches of water column or more, and you choose to monitor the liquid-to-gas ratio, rather than only the influent liquid flow, and you want the ability to lower liquid flow with changes in gas flow.	Liquid-to-gas ratio as determined by dividing the influent liquid flow rate by the inlet gas flow rate. The units of measure must be consistent with those used to calculate this ratio during the performance test.	You must measure the gas stream by: Measuring the gas stream flow at the absorber inlet; or Using the design blower capacity, with appropriate adjustments for pressure drop.
Install CPMS for pressure at the gas stream inlet and outlet of the absorber.	Your absorber is designed and operated with pressure drops of 5 inches of water column or more.	Pressure drop through the absorber.	You may measure the pressure of the inlet gas using amperage on the blower if a correlation between pressure and amperage is established
Sorbent Injection			
Install a CPMS for flow rate	....	Sorbent injection rate.	
Install a CPMS for flow rate	....	Sorbent injection carrier gas flow rate.	
Wet Electrostatic Precipitators			
Install secondary voltage meter.	You control mercury or metal HAP (particulate matter) using an electrostatic precipitator.	Secondary voltage.	

TABLE 4 TO SUBPART AA OF PART 63—OPERATING PARAMETERS, OPERATING LIMITS AND DATA MONITORING, RECORDKEEPING AND COMPLIANCE FREQUENCIES

For the operating parameter applicable to you, as specified in Table 3 . . .	You must establish the following operating limit . . .	And you must monitor, record, and demonstrate continuous compliance using these minimum frequencies . . .		
		Data measurement	Data recording	Data averaging period for compliance
Absorbers (Wet Scrubbers)				
Influent liquid flow	Minimum inlet liquid flow	Continuous	Every 15 minutes.	Daily.
Influent liquid flow rate and gas stream flow rate.	Minimum influent liquid-to-gas ratio	Continuous	Every 15 minutes.	Daily.

TABLE 4 TO SUBPART AA OF PART 63—OPERATING PARAMETERS, OPERATING LIMITS AND DATA MONITORING, RECORDKEEPING AND COMPLIANCE FREQUENCIES—Continued

For the operating parameter applicable to you, as specified in Table 3 . . .	You must establish the following operating limit . . .	And you must monitor, record, and demonstrate continuous compliance using these minimum frequencies . . .		
		Data measurement	Data recording	Data averaging period for compliance
Pressure drop	Pressure drop range	Continuous	Every 15 minutes.	Daily.
Sorbent Injection				
Sorbent injection rate	Minimum injection rate	Continuous	Every 15 minutes.	Daily.
Sorbent injection carrier gas flow rate.	Minimum carrier gas flow rate	Continuous	Every 15 minutes.	Daily.
Fabric Filters				
Alarm time	Maximum alarm time is not established on a site-specific basis but is specified in § 63.605(f)(9).	Continuous	Each date and time of alarm start and stop.	Maximum alarm time specified in § 63.605(f)(9).
Wet Electrostatic Precipitator				
Secondary voltage	Secondary voltage range	Continuous	Every 15 minutes.	Daily.

TABLE 5 TO SUBPART AA OF PART 63—CALIBRATION AND QUALITY CONTROL REQUIREMENTS FOR CONTINUOUS PARAMETER MONITORING SYSTEM (CPMS)

If you monitor this parameter . . .	Your accuracy requirements are . . .	And your calibration requirements are . . .
Temperature	±1 percent over the normal range of temperature measured or 2.8 degrees Celsius (5 degrees Fahrenheit), whichever is greater, for non-cryogenic temperature ranges. ±2.5 percent over the normal range of temperature measured or 2.8 degrees Celsius (5 degrees Fahrenheit), whichever is greater, for cryogenic temperature ranges.	Performance evaluation annually and following any period of more than 24 hours throughout which the temperature exceeded the maximum rated temperature of the sensor, or the data recorder was off scale. Visual inspections and checks of CPMS operation every 3 months, unless the CPMS has a redundant temperature sensor. Selection of a representative measurement location.
Flow Rate	±5 percent over the normal range of flow measured or 1.9 liters per minute (0.5 gallons per minute), whichever is greater, for liquid flow rate. ±5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute), whichever is greater, for gas flow rate. ±5 percent over the normal range measured for mass flow rate.	Performance evaluation annually and following any period of more than 24 hours throughout which the flow rate exceeded the maximum rated flow rate of the sensor, or the data recorder was off scale. Checks of all mechanical connections for leakage monthly. Visual inspections and checks of CPMS operation every 3 months, unless the CPMS has a redundant flow sensor. Selection of a representative measurement location where swirling flow or abnormal velocity distributions due to upstream and downstream disturbances at the point of measurement are minimized.
Pressure	±5 percent over the normal range measured or 0.12 kilopascals (0.5 inches of water column), whichever is greater.	Checks for obstructions (*e.g.,* pressure tap pluggage) at least once each process operating day. Performance evaluation annually and following any period of more than 24 hours throughout which the pressure exceeded the maximum rated pressure of the sensor, or the data recorder was off scale. Checks of all mechanical connections for leakage monthly. Visual inspection of all components for integrity, oxidation and galvanic corrosion every 3 months, unless the CPMS has a redundant pressure sensor. Selection of a representative measurement location that minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.

TABLE 5 TO SUBPART AA OF PART 63—CALIBRATION AND QUALITY CONTROL REQUIREMENTS FOR CONTINUOUS PARAMETER MONITORING SYSTEM (CPMS)—Continued

If you monitor this parameter . . .	Your accuracy requirements are . . .	And your calibration requirements are . . .
Sorbent Injection Rate	±5 percent over the normal range measured	Performance evaluation annually. Visual inspections and checks of CPMS operation every 3 months, unless the CPMS has a redundant sensor. Select a representative measurement location that provides measurement of total sorbent injection.
Secondary voltage	±1kV	

APPENDIX A TO SUBPART AA OF PART 63—APPLICABILITY OF GENERAL PROVISIONS (40 CFR PART 63, SUBPART A) TO SUBPART AA

40 CFR citation	Requirement	Applies to subpart AA	Comment
§ 63.1(a)(1) through (4)	General Applicability	Yes	None.
§ 63.1(a)(5)		No	[Reserved].
§ 63.1(a)(6)	Contact information	Yes	None.
§ 63.1(a)(7)–(9)		No	[Reserved].
§ 63.1(a)(10) through (12)	Time periods	Yes	None.
§ 63.1(b)	Initial Applicability Determination	Yes	None.
§ 63.1(c)(1)	Applicability After Standard Established	Yes	None.
§ 63.1(c)(2)	Permits	Yes	Some plants may be area sources.
§ 63.1(c)(3)–(4)		No	[Reserved].
§ 63.1(c)(5)	Area to Major source change	Yes	None.
§ 63.1(d)		No	[Reserved].
§ 63.1(e)	Applicability of Permit Program	Yes	None.
§ 63.2	Definitions	Yes	Additional definitions in § 63.601.
§ 63.3	Units and Abbreviations	Yes	None.
§ 63.4(a)(1) and (2)	Prohibited Activities	Yes	None.
§ 63.4(a)(3) through (5)		No	[Reserved].
§ 63.4(b) and (c)	Circumvention/Fragmentation	Yes	None.
§ 63.5(a)	Construction/Reconstruction Applicability.	Yes	None.
§ 63.5(b)(1)	Existing, New, Reconstructed Sources Requirements.	Yes	None.
§ 63.5(b)(2)		No	[Reserved].
§ 63.5(b)(3), (4), and (6)	Construction/Reconstruction approval and notification.	Yes	None.
§ 63.5(b)(5)		No	[Reserved].
§ 63.5(c)		No	[Reserved].
§ 63.5(d)	Application for Approval of Construction/Reconstruction.	Yes	None.
§ 63.5(e)	Approval of Construction/Reconstruction	Yes	None.
§ 63.5(f)	Approval of Construction/Reconstruction Based on State Review.	Yes	None.
§ 63.6(a)	Compliance with Standards and Maintenance Applicability.	Yes	None.
§ 63.6(b)(1) through (5)	New and Reconstructed Sources Dates	Yes	See also § 63.602.
§ 63.6(b)(6)		No	[Reserved].
§ 63.6(b)(7)	Area to major source change	Yes	None.
§ 63.6(c)(1)and (2)	Existing Sources Dates	Yes	§ 63.602 specifies dates.
§ 63.6(c)(3) and (4)		No	[Reserved].
§ 63.6(c)(5)	Area to major source change	Yes	None.
§ 63.6(d)		No	[Reserved].
§ 63.6(e)(1)(i) and (ii)	Operation & Maintenance Requirements	No	See § 63.608(b) for general duty requirement.
§ 63.6(e)(iii)		Yes	None.
§ 63.6(e)(2)		No	[Reserved].
§ 63.6(e)(3)	Startup, Shutdown, and Malfunction Plan.	No	None.
§ 63.6(f)	Compliance with Emission Standards	No	See general duty at § 63.608(b).
§ 63.6(g)	Alternative Standard	Yes	None.
§ 63.6(h)	Compliance with Opacity/VE Standards	No	Subpart AA does not include VE/opacity standards.
§ 63.6(i)(1) through (14)	Extension of Compliance	Yes	None.
§ 63.6(i)(15)		No	[Reserved].
§ 63.6(i)(16)		Yes	None.
§ 63.6(j)	Exemption from Compliance	Yes	None.
§ 63.7(a)	Performance Test Requirements Applicability.	Yes	None.

APPENDIX A TO SUBPART AA OF PART 63—APPLICABILITY OF GENERAL PROVISIONS (40 CFR PART 63, SUBPART A) TO SUBPART AA—Continued

40 CFR citation	Requirement	Applies to subpart AA	Comment
§ 63.7(b)	Notification	Yes	None.
§ 63.7(c)	Quality Assurance/Test Plan	Yes	None.
§ 63.7(d)	Testing Facilities	Yes	None.
§ 63.7(e)(1)	Conduct of Tests; startup, shutdown, and malfunction provisions.	No	§ 63.606 specifies additional requirements.
§ 63.7(e)(2) through (4)	Conduct of Tests	Yes	§ 63.606 specifies additional requirements.
§ 63.7(f)	Alternative Test Method	Yes	None.
§ 63.7(g)	Data Analysis	Yes	None.
§ 63.7(h)	Waiver of Tests	Yes	None.
§ 63.8(a)	Monitoring Requirements Applicability	Yes	None.
§ 63.8(b)	Conduct of Monitoring	Yes	None.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No	See 63.608(b) for general duty requirement.
§ 63.8(c)(1)(ii)		Yes	None.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS.	No	None.
§ 63.8(c)(2) through (4)	CMS Operation/Maintenance	Yes	None.
§ 63.8(c)(5)	COMS Operation	No	Subpart AA does not require COMS.
§ 63.8(c)(6) through (8)	CMS requirements	Yes	None.
§ 63.8(d)(1) and (2)	Quality Control	Yes	None.
§ 63.8(d)(3)	Written procedure for CMS	No	See § 63.608 for requirement.
§ 63.8(e)	CMS Performance Evaluation	Yes	None.
§ 63.8(f)(1) through (5)	Alternative Monitoring Method	Yes	None.
§ 63.8(f)(6)	Alternative to RATA Test	Yes	None.
§ 63.8(g)(1)	Data Reduction	Yes	None.
§ 63.8(g)(2)		Yes	None.
§ 63.8(g)(3) through (5)		Yes	None.
§ 63.9(a)	Notification Requirements Applicability	Yes	None.
§ 63.9(b)	Initial Notifications	Yes	None.
§ 63.9(c)	Request for Compliance Extension	Yes	None.
§ 63.9(d)	New Source Notification for Special Compliance Requirements.	Yes	None.
§ 63.9(e)	Notification of Performance Test	Yes	None.
§ 63.9(f)	Notification of VE/Opacity Test	No	Subpart AA does not include VE/opacity standards.
§ 63.9(g)	Additional CMS Notifications	Yes	Subpart AA does not require CMS performance evaluation, COMS, or CEMS.
§ 63.9(h)(1) through (3)	Notification of Compliance Status	Yes	None.
§ 63.9(h)(4)		No	[Reserved].
§ 63.9(h)(5) and (6)		Yes	None.
§ 63.9(i)	Adjustment of Deadlines	Yes	None.
§ 63.9(j)	Change in Previous Information	Yes	None.
§ 63.10(a)	Recordkeeping/Reporting-Applicability	Yes	None.
§ 63.10(b)(1)	General Recordkeeping Requirements	Yes	None.
§ 63.10(b)(2)(i)	Startup or shutdown duration	No	None.
§ 63.10(b)(2)(ii)	Malfunction	No	See § 63.607 for recordkeeping and reporting requirement.
§ 63.10(b)(2)(iii)	Maintenance records	Yes	None.
§ 63.10(b)(2)(iv) and (v)	Startup, shutdown, malfunction actions	No	None.
§ 63.10(b)(2)(vi) through (xiv)	General Recordkeeping Requirements	Yes	None.
§ 63.10(b)(3)	General Recordkeeping Requirements	Yes	None.
§ 63.10(c)(1)	Additional CMS Recordkeeping	Yes	None.
§ 63.10(c)(2) through (4)		No	[Reserved].
§ 63.10(c)(5)		Yes	None.
§ 63.10(c)(6)		Yes	None.
§ 63.10(c)(7) and (8)		Yes	None.
§ 63.10(c)(9)		No	[Reserved].
§ 63.10(c)(10) through (13)		Yes	None.
§ 63.10(c)(14)		Yes	None.
§ 63.10(c)(15)	Startup Shutdown Malfunction Plan Provisions.	No	None.
§ 63.10(d)(1)	General Reporting Requirements	Yes	None.
§ 63.10(d)(2)	Performance Test Results	Yes	None.
§ 63.10(d)(3)	Opacity or VE Observations	No	Subpart AA does not include VE/opacity standards.
§ 63.10(d)(4)	Progress Reports	Yes	None.
§ 63.10(d)(5)	Startup, Shutdown, and Malfunction Reports.	No	See § 63.607 for reporting of excess emissions.

APPENDIX A TO SUBPART AA OF PART 63—APPLICABILITY OF GENERAL PROVISIONS (40 CFR PART 63, SUBPART A) TO SUBPART AA—Continued

40 CFR citation	Requirement	Applies to subpart AA	Comment
§ 63.10(e)(1) and (2)	Additional CMS Reports	Yes	None.
§ 63.10(e)(3)	Excess Emissions/CMS Performance Reports.	Yes	None.
§ 63.10(e)(4)	COMS Data Reports	No	Subpart AA does not require COMS.
§ 63.10(f)	Recordkeeping/Reporting Waiver	Yes	None.
§ 63.11	Control Device and Work Practice Requirements.	Yes	None.
§ 63.12	State Authority and Delegations	Yes	None.
§ 63.13	Addresses	Yes	None.
§ 63.14	Incorporation by Reference	Yes	None.
§ 63.15	Information Availability/Confidentiality	Yes	None.
§ 63.16	Performance Track Provisions	No	Terminated.

■ 21. Part 63 is amended by revising subpart BB to read as follows:

Subpart BB—National Emission Standards for Hazardous Air Pollutants from Phosphate Fertilizers Production Plants

Sec.
63.620 Applicability.
63.621 Definitions.
63.622 Standards and compliance dates.
63.623 [Reserved]
63.624 [Reserved]
63.625 Operating and monitoring requirements.
63.626 Performance tests and compliance provisions.
63.627 Notification, recordkeeping, and reporting requirements.
63.628 General requirements and applicability of general provisions of this part.
63.629 Miscellaneous requirements.
63.630 [Reserved]
63.631 Exemption from new source performance standards.
63.632 Implementation and enforcement.
Table 1 to Subpart BB of Part 63—Existing Source Emission Limits
Table 2 to Subpart BB of Part 63—New Source Emission Limits
Table 3 to Subpart BB of Part 63—Monitoring Equipment Operating Parameters
Table 4 to Subpart BB of Part 63—Operating Parameters, Operating Limits and Data Monitoring, Recordkeeping and Compliance Frequencies
Table 5 to Subpart BB of Part 63—Calibration and Quality Control Requirements for Continuous Parameter Monitoring Systems (CPMS)
Appendix A to Subpart BB of Part 63—Applicability of General Provisions (40 CFR part 63, subpart A) to Subpart BB

§ 63.620 Applicability.

(a) Except as provided in paragraphs (c) and (d) of this section, you are subject to the requirements of this subpart if you own or operate a phosphate fertilizer production plant that is a major source as defined in § 63.2. You must comply with the emission limitations, work practice standards, and operating parameter requirements specified in this subpart at all times.

(b) The requirements of this subpart apply to emissions of hazardous air pollutants (HAP) emitted from the following affected sources at a phosphate fertilizer production plant:

(1) Each phosphate fertilizer process line (*e.g.,* diammonium and/or monoammonium phosphate process line).

(2) Each granular triple superphosphate process line.

(3) Each granular triple superphosphate storage building.

(4) Evaporative cooling tower.

(c) The requirements of this subpart do not apply to a phosphate fertilizer production plant that is an area source as defined in § 63.2.

(d) The provisions of this subpart do not apply to research and development facilities as defined in § 63.621.

§ 63.621 Definitions.

Terms used in this subpart are defined in § 63.2 of the Clean Air Act and in this section as follows:

Diammonium and/or monoammonium phosphate process line means any process line manufacturing granular diammonium and/or monoammonium phosphate by reacting ammonia with phosphoric acid that has been derived from or manufactured by reacting phosphate rock and acid. A diammonium and/or monoammonium phosphate process line includes: Reactors, granulators, dryers, coolers, screens, and mills.

Equivalent P_2O_5 feed means the quantity of phosphorus, expressed as phosphorus pentoxide (P_2O_5), fed to the process.

Equivalent P_2O_5 stored means the quantity of phosphorus, expressed as phosphorus pentoxide, being cured or stored in the affected facility.

Evaporative cooling tower means an open-water, re-circulating device that uses fans or natural draft to draw or force ambient air through the device to remove heat from process water by direct contact.

Exceedance means a departure from an indicator range established for monitoring under this subpart, consistent with any averaging period specified for averaging the results of the monitoring.

Existing source depends on the date that construction or reconstruction of an affected source commenced. A phosphate fertilizer process line (*e.g.,* diammonium and/or monoammonium phosphate process line), granular triple superphosphate process line, or granular triple superphosphate storage is an existing source if construction or reconstruction of the affected source commenced on or before December 27, 1996.

Fresh granular triple superphosphate means granular triple superphosphate produced within the preceding 72 hours.

Granular triple superphosphate process line means any process line, not including storage buildings, that manufactures granular triple superphosphate by reacting phosphate rock with phosphoric acid. A granular triple superphosphate process line includes: mixers, curing belts (dens), reactors, granulators, dryers, coolers, screens, and mills.

Granular triple superphosphate storage building means any building curing or storing fresh granular triple superphosphate. A granular triple superphosphate storage building includes: storage or curing buildings, conveyors, elevators, screens, and mills.

New source depends on the date that construction or reconstruction of an affected source commences. A phosphate fertilizer process line (*e.g.,* diammonium and/or monoammonium phosphate process line), granular triple superphosphate process line, or granular triple superphosphate storage is a new source if construction or reconstruction of the affected source commenced after December 27, 1996.

Phosphate fertilizer process line means any process line that manufactures a granular phosphate fertilizer by reacting phosphoric acid with ammonia. A phosphate fertilizer process line includes: reactors, granulators, dryers, coolers, screens, and mills.

Phosphate fertilizer production plant means any production plant that manufactures a granular phosphate fertilizer by reacting phosphoric acid with ammonia.

Research and development facility means research or laboratory operations whose primary purpose is to conduct research and development into new processes and products, where the operations are under the close supervision of technically trained personnel, and where the facility is not engaged in the manufacture of products for commercial sale in commerce or other off-site distribution, except in a de minimis manner.

Shutdown commences when feed materials cease to be added to an affected source and ends when the affected source is deactivated, regardless of whether feed material is present in the affected source.

Startup commences when any feed material is first introduced into an affected source and ends when feed material is fully loaded into the affected source.

Total fluorides means elemental fluorine and all fluoride compounds, including the HAP hydrogen fluoride, as measured by reference methods specified in 40 CFR part 60, appendix A, Method 13 A or B, or by equivalent or alternative methods approved by the Administrator pursuant to § 63.7(f).

§ 63.622 Standards and compliance dates.

(a) On and after the dates specified in paragraphs (a)(1) through (3) of this section, for each phosphate fertilizer process line (*e.g.,* diammonium and/or monoammonium phosphate process line), granular triple superphosphate process line, and granular triple superphosphate storage building, you must comply with the emission limits as specified in paragraphs (a)(1) through (3) of this section. If a process line contains more than one emission point, you must sum the emissions from all emission points in a process line to determine compliance with the specified emission limits.

(1) For each existing phosphate fertilizer process line (*e.g.,* diammonium and/or monoammonium phosphate process line), granular triple superphosphate process line, and granular triple superphosphate storage building that commenced construction or reconstruction on or before December 27, 1996, you must comply with the emission limits specified in Table 1 to this subpart beginning on June 10, 2002.

(2) For each new phosphate fertilizer process line (*e.g.,* diammonium and/or monoammonium phosphate process line), granular triple superphosphate process line, and granular triple superphosphate storage building that commences construction or reconstruction after December 27, 1996 and on or before August 19, 2015, you must comply with the emission limits specified in Table 2 to this subpart beginning on June 10, 1999 or at startup, whichever is later.

(3) For each new phosphate fertilizer process line (*e.g.,* diammonium and/or monoammonium phosphate process line), granular triple superphosphate process line, and granular triple superphosphate storage building that commences construction or reconstruction after August 19, 2015, you must comply with the emission limits specified in Table 2 to this subpart immediately upon startup.

(b) Beginning on June 10, 2002, you must not ship fresh granular triple superphosphate from your existing granular triple superphosphate storage building that commenced construction or reconstruction on or before December 27, 1996. Beginning on June 10, 1999 or at startup, whichever is later, you must not ship fresh granular triple superphosphate from your new granular triple superphosphate storage building that commences construction or reconstruction after December 27, 1996.

(c) Beginning on August 19, 2015, you must not introduce into any evaporative cooling tower any liquid effluent from any absorber installed to control emissions from process equipment.

(d) Beginning on August 19, 2015, during periods of startup and shutdown (as defined in § 63.621), you must comply with the work practice specified in this paragraph in lieu of the emission limits specified in paragraph (a) of this section. During periods of startup and shutdown, you must operate any control device(s) being used at the affected source, monitor the operating parameters specified in Table 3 of this subpart, and comply with the operating limits specified in Table 4 of this subpart.

§ 63.623 [Reserved]

§ 63.624 [Reserved]

§ 63.625 Operating and monitoring requirements.

(a) For each phosphate fertilizer process line (*e.g.,* diammonium and/or monoammonium phosphate process line), or granular triple superphosphate process line subject to the provisions of this subpart, you must comply with the monitoring requirements specified in paragraphs (a)(1) and (2) of this section.

(1) Install, calibrate, maintain, and operate a continuous monitoring system (CMS) according to your site-specific monitoring plan specified in § 63.628(c). The CMS must have an accuracy of ±5 percent over its operating range and must determine and permanently record the mass flow of phosphorus-bearing material fed to the process.

(2) Maintain a daily record of equivalent P_2O_5 feed. Calculate the equivalent P_2O_5 feed by determining the total mass rate in metric ton/hour of phosphorus bearing feed using the procedures specified in § 63.626(f)(3).

(b) For each granular triple superphosphate storage building subject to the provisions of this subpart, you must maintain an accurate record of the mass of granular triple superphosphate in storage to permit the determination of the amount of equivalent P_2O_5 stored.

(c) For each granular triple superphosphate storage building subject to the provisions of this subpart, you must comply with the requirements specified in paragraphs (c)(1) and (2) of this section.

(1) Maintain a daily record of total equivalent P_2O_5 stored by multiplying the percentage P_2O_5 content, as determined by § 63.626(f)(3)(ii), by the total mass of granular triple superphosphate stored as specified in paragraph (b) of this section.

(2) Develop for approval by the Administrator a site-specific methodology including sufficient recordkeeping for the purposes of demonstrating compliance with § 63.622(b).

(d) If you use a control device(s) to comply with the emission limits specified in Table 1 or 2 of this subpart, you must install a continuous parameter monitoring system (CPMS) and comply with the requirements specified in paragraphs (d)(1) through (4) of this section.

(1) You must monitor the operating parameter(s) applicable to the control device that you use as specified in Table 3 to this subpart and establish the applicable limit or range for the operating parameter limit as specified in

paragraphs (d)(1)(i) and (ii) of this section, as applicable.

(i) Except as specified in paragraph (d)(1)(ii) of this section, determine the value(s) as the arithmetic average of operating parameter measurements recorded during the three test runs conducted for the most recent performance test.

(ii) If you use an absorber to comply with the emission limits in Table 1 or 2 to this subpart and you monitor pressure drop across the absorber, you must establish allowable ranges using the methodology specified in paragraphs (d)(1)(ii)(A) and (B) of this section.

(A) The allowable range for the daily averages of the pressure drop across each absorber is ±20 percent of the baseline average value determined in paragraph (d)(1)(i) of this section. The Administrator retains the right to reduce the ±20 percent adjustment to the baseline average values of operating ranges in those instances where performance test results indicate that a source's level of emissions is near the value of an applicable emissions standard. However, the adjustment must not be reduced to less than ±10 percent under any instance.

(B) As an alternative to paragraph (d)(1)(ii)(A) of this section, you may establish allowable ranges for the daily averages of the pressure drop across an absorber for the purpose of assuring compliance with this subpart using the procedures described in this paragraph. You must establish the allowable ranges based on the baseline average values recorded during previous performance tests or the results of performance tests conducted specifically for the purposes of this paragraph. You must conduct all performance tests using the methods specified in § 63.626. You must certify that the control devices and processes have not been modified since the date of the performance test from which you obtained the data used to establish the allowable ranges. When a source using the methodology of this paragraph is retested, you must determine new allowable ranges of baseline average values unless the retest indicates no change in the operating parameters outside the previously established ranges.

(2) You must monitor, record, and demonstrate continuous compliance using the minimum frequencies specified in Table 4 to this subpart.

(3) You must comply with the calibration and quality control requirements that are applicable to the operating parameter(s) you monitor as specified in Table 5 to this subpart.

(4) If you use a fabric filter system to comply with the emission limits specified in Table 1 or 2 to this subpart, the system must meet the requirements for fabric filters specified in paragraph (e) of this section.

(e) Beginning August 19, 2016, if you use a fabric filter system to comply with the emission limits specified in Table 1 or 2 to this subpart, then the fabric filter must be equipped with a bag leak detection system that is installed, calibrated, maintained and continuously operated according to the requirements in paragraphs (e)(1) through (10) of this section.

(1) Install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute particulate matter loadings for each exhaust stack, roof vent, or compartment (*e.g.,* for a positive-pressure fabric filter) of the fabric filter.

(2) Use a bag leak detection system certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic feet) or less.

(3) Use a bag leak detection system equipped with a device to continuously record the output signal from the system sensor.

(4) Use a bag leak detection system equipped with a system that will trigger an alarm when an increase in relative particulate material emissions over a preset level is detected. The alarm must be located such that the alert is observed readily by plant operating personnel.

(5) Install a bag leak detection system in each compartment or cell for positive-pressure fabric filter systems that do not duct all compartments or cells to a common stack. Install a bag leak detector downstream of the fabric filter if a negative-pressure or induced-air filter is used. If multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

(6) Calibration of the bag leak detection system must, at a minimum, consist of establishing the baseline output level by adjusting the range and the averaging period of the device and establishing the alarm set points and the alarm delay time.

(7) After initial adjustment, you must not adjust the sensitivity or range, averaging period, alarm set points or alarm delay time, except as established in your site-specific monitoring plan required in § 63.628(c). In no event may the sensitivity be increased more than 100 percent or decreased by more than 50 percent over a 365-day period unless such adjustment follows a complete inspection of the fabric filter system that demonstrates that the system is in good operating condition.

(8) Operate and maintain each fabric filter and bag leak detection system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. If the alarm sounds more than 5 percent of the operating time during a 6-month period, it is considered an operating parameter exceedance. Calculate the alarm time (*i.e.,* time that the alarm sounds) as specified in paragraphs (e)(8)(i) through (iii) of this section.

(i) If inspection of the fabric filter demonstrates that corrective action is not required, the alarm duration is not counted in the alarm time calculation.

(ii) If corrective action is required, each alarm time is counted as a minimum of 1 hour.

(iii) If it takes longer than 1 hour to initiate corrective action, each alarm time (*i.e.,* time that the alarm sounds) is counted as the actual amount of time taken by you to initiate corrective action.

(9) If the alarm on a bag leak detection system is triggered, you must initiate procedures within 1 hour of an alarm to identify the cause of the alarm and then initiate corrective action, as specified in § 63.628(d)(2), no later than 48 hours after an alarm. Failure to take these actions within the prescribed time periods is considered a violation.

(10) Retain records of any bag leak detection system alarm, including the date, time, duration, and the percent of the total operating time during each 6-month period that the alarm triggers, with a brief explanation of the cause of the alarm, the corrective action taken, and the schedule and duration of the corrective action.

§ 63.626 Performance tests and compliance provisions.

(a) You must conduct an initial performance test to demonstrate compliance with the emission limits specified in Tables 1 and 2 to this subpart, within 180 days of the applicable compliance date specified in § 63.622.

(b) After you conduct the initial performance test specified in paragraph (a) of this section, you must conduct a performance test once per calendar year.

(c) For affected sources (as defined in § 63.620) that have not operated since the previous annual performance test was conducted and more than 1 year has passed since the previous performance test, you must conduct a performance test no later than 180 days after the re-start of the affected source according to the applicable provisions in § 63.7(a)(2).

(d)(1) You must conduct the performance tests specified in this section at representative (normal) conditions for the process. Representative (normal) conditions means those conditions that:

(i) Represent the range of combined process and control measure conditions under which the facility expects to operate (regardless of the frequency of the conditions); and

(ii) Are likely to most challenge the emissions control measures of the facility with regard to meeting the applicable emission standards, but without creating an unsafe condition.

(2) Operations during startup, shutdown, and malfunction do not constitute representative (normal) operating conditions for purposes of conducting a performance test. You must record the process information that is necessary to document the operating conditions during the test and include in such record an explanation to support that such conditions represent representative (normal) conditions. Upon request, you must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(e) In conducting all performance tests, you must use as reference methods and procedures the test methods in 40 CFR part 60, appendix A, or other methods and procedures as specified in this section, except as provided in § 63.7(f).

(f) For each phosphate fertilizer process line (*e.g.,* diammonium and/or monoammonium phosphate process line), and granular triple superphosphate process line, you must determine compliance with the applicable total fluorides standards specified in Tables 1 and 2 to this subpart as specified in paragraphs (f)(1) through (3) of this section.

(1) Compute the emission rate (E) of total fluorides for each run using Equation BB–1:

$$E = \left(\sum_{i=1}^{N} C_i Q_i \right) / (PK) \qquad \text{(Eq. BB-1)}$$

Where:

E = Emission rate of total fluorides, gram/metric ton (pound/ton) of equivalent P_2O_5 feed.

Ci = Concentration of total fluorides from emission point ''i,'' milligram/dry standard cubic meter (milligram/dry standard cubic feet).

Qi = Volumetric flow rate of effluent gas from emission point ''i,'' dry standard cubic meter/hour (dry standard cubic feet/hour).

N = Number of emission points associated with the affected facility.

P = Equivalent P_2O_5 feed rate, metric ton/hour (ton/hour).

K = Conversion factor, 1000 milligram/gram (453,600 milligram/pound).

(2) You must use Method 13A or 13B (40 CFR part 60, appendix A) to determine the total fluorides concentration (C_i) and the volumetric flow rate (Q_i) of the effluent gas at each emission point. The sampling time for each run at each emission point must be at least 60 minutes. The sampling volume for each run at each emission point must be at least 0.85 dscm (30 dscf). If Method 13B is used, the fusion of the filtered material described in Section 7.3.1.2 and the distillation of suitable aliquots of containers 1 and 2, described in section 7.3.3 and 7.3.4 in Method 13 A, may be omitted.

(3) Compute the equivalent P_2O_5 feed rate (P) using Equation BB–2:

$$P = M_p R_p \qquad \text{(Eq. BB-2)}$$

Where:

P = P_2O_5 feed rate, metric ton/hour (ton/hour).

M_p = Total mass flow rate of phosphorus-bearing feed, metric ton/hour (ton/hour).

R_p = P_2O_5 content, decimal fraction.

(i) Determine the mass flow rate (M_p) of the phosphorus-bearing feed using the measurement system described in § 63.625(a).

(ii) Determine the P_2O_5 content (R_p) of the feed using, as appropriate, the following methods specified in the Book of Methods Used and Adopted By The Association of Florida Phosphate Chemists (incorporated by reference, see § 63.14) where applicable:

(A) Section IX, Methods of Analysis for Phosphate Rock, No. 1 Preparation of Sample.

(B) Section IX, Methods of Analysis for Phosphate Rock, No. 3 Phosphorus-P_2O_5 or $Ca_3(PO_4)_2$, Method A—Volumetric Method.

(C) Section IX, Methods of Analysis for Phosphate Rock, No. 3 Phosphorus-P_2O_5 or $Ca_3(PO_4)_2$, Method B—Gravimetric Quimociac Method.

(D) Section IX, Methods of Analysis for Phosphate Rock, No. 3 Phosphorus-P_2O_5 or Ca3(PO4)2, Method C—Spectrophotometric Method.

(E) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P_2O_5, Method A—Volumetric Method.

(F) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P_2O_5, Method B—Gravimetric Quimociac Method.

(G) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P_2O_5, Method C—Spectrophotometric Method.

(g) For each granular triple superphosphate storage building, you must determine compliance with the applicable total fluorides standards specified in Tables 1 and 2 to this subpart as specified in paragraphs (g)(1) through (7) of this section.

(1) You must conduct performance tests only when the following quantities of product are being cured or stored in the facility:

(i) Total granular triple superphosphate is at least 10 percent of the building capacity, and

(ii) Fresh granular triple superphosphate is at least six percent of the total amount of granular triple superphosphate, or

(iii) If the provision in paragraph (g)(1)(ii) of this section exceeds production capabilities for fresh granular triple superphosphate, the fresh granular triple superphosphate is equal to at least 5 days maximum production.

(2) Compute the emission rate (E) of total fluorides for each run using Equation BB–3:

$$E = \left(\sum_{i=1}^{N} C_i Q_i \right) / (PK) \qquad \text{(Eq. BB-3)}$$

Where:

E = Emission rate of total fluorides, gram/hour/metric ton (pound/hour/ton) of equivalent P_2O_5 stored.

C_i = Concentration of total fluorides from emission point ''i'', milligram/dry standard cubic meter (milligram/dry standard cubic feet).

Q_i = Volumetric flow rate of effluent gas from emission point ''i'', dry standard cubic meter/hour (dry standard cubic feet/hour).

N = Number of emission points in the affected facility.

P = Equivalent P_2O_5 stored, metric tons (tons).

K = Conversion factor, 1000 milligram/gram (453,600 milligram/pound).

(3) You must use Method 13A or 13B (40 CFR part 60, appendix A) to determine the total fluorides concentration (C_i) and the volumetric flow rate (Q_i) of the effluent gas at each emission point. The sampling time for each run at each emission point must be at least 60 minutes. The sampling volume for each run at each emission point must be at least 0.85 dscm (30 dscf). If Method 13B is used, the fusion of the filtered material described in Section 7.3.1.2 and the distillation of suitable aliquots of containers 1 and 2, described in section 7.3.3 and 7.3.4 in Method 13A, may be omitted.

(4) Compute the equivalent P_2O_5 stored (P) using Equation BB–4:

$$P = M_p R_p \qquad \text{(Eq. BB-4)}$$

Where:

P = P_2O_5 stored (ton).

M_p = Amount of product in storage, metric ton (ton).

R_p = P_2O_5 content of product in storage, weight fraction.

(5) Determine the amount of product (M_p) in storage using the measurement system described in § 63.625(b) and (c).

(6) Determine the P_2O_5 content (R_p) of the product stored using, as appropriate, the following methods specified in the Book of Methods Used and Adopted By The Association of Florida Phosphate Chemists (incorporated by reference, see § 63.14) where applicable:

(i) Section XI, Methods of Analysis For Phosphoric Acid, Superphosphate, Triple superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P_2O_5, Method A—Volumetric Method.

(ii) Section XI, Methods of Analysis For Phosphoric Acid, Superphosphate, Triple superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P_2O_5, Method B—Gravimetric Quimociac Method.

(iii) Section XI, Methods of Analysis For Phosphoric Acid, Superphosphate, Triple superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P_2O_5, Method C—Spectrophotometric Method, or,

(7) Determine the P_2O_5 content (R_p) of the product stored using, as appropriate, the following methods specified in the Official Methods of Analysis of AOAC International (incorporated by reference, see § 63.14) where applicable:

(i) AOAC Official Method 957.02 Phosphorus (Total) In Fertilizers, Preparation of Sample Solution.

(ii) AOAC Official Method 929.01 Sampling of Solid Fertilizers.

(iii) AOAC Official Method 929.02 Preparation of Fertilizer Sample.

(iv) AOAC Official Method 978.01 Phosphorus (Total) in Fertilizers, Automated Method.

(v) AOAC Official Method 969.02 Phosphorus (Total) in Fertilizers, Alkalimetric Quinolinium Molybdophosphate Method.

(vi) AOAC Official Method 962.02 Phosphorus (Total) in Fertilizers, Gravimetric Quinolinium Molybdophosphate Method.

(vii) AOAC Official Method 958.01 Phosphorus (Total) in Fertilizers, Spectrophotometric Molybdovanadophosphate Method.

(h) If you use a CMS, you must conduct a performance evaluation, as specified in § 63.8(e), in accordance with your site-specific monitoring plan in § 63.628(c). For fabric filters, you must conduct a performance evaluation of the bag leak detection system consistent with the guidance provided in Office Of Air Quality Planning And Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance (incorporated by reference, see § 63.14). You must record the sensitivity of the bag leak detection system to detecting changes in particulate matter emissions, range, averaging period, and alarm set points during the performance test.

§ 63.627 Notification, recordkeeping, and reporting requirements.

(a) You must comply with the notification requirements specified in § 63.9. During the most recent performance test, if you demonstrate compliance with the emission limit while operating your control device outside the previously established operating limit, you must establish a new operating limit based on that most recent performance test and notify the Administrator that the operating limit changed based on data collected during the most recent performance test. When a source is retested and the performance test results are submitted to the Administrator pursuant to paragraph (b)(1) of this section, § 63.7(g)(1), or § 63.10(d)(2), you must indicate whether the operating limit is based on the new performance test or the previously established limit. Upon establishment of a new operating limit, you must thereafter operate under the new operating limit. If the Administrator determines that you did not conduct the compliance test in accordance with the applicable requirements or that the operating limit established during the performance test does not correspond to representative (normal) conditions, you must conduct a new performance test and establish a new operating limit.

(b) You must comply with the reporting and recordkeeping requirements in § 63.10 as specified in paragraphs (b)(1) through (5) of this section.

(1) You must comply with the general recordkeeping requirements in § 63.10(b)(1); and

(2) As required by § 63.10(d), you must report the results of the initial and subsequent performance tests as part of the notification of compliance status required in § 63.9(h). You must verify in the performance test reports that the operating limits for each process have not changed or provide documentation of revised operating limits established according to § 63.625, as applicable. In the notification of compliance status, you must also:

(i) Certify to the Administrator that you have not shipped fresh granular triple superphosphate from an affected facility.

(ii) Certify to the Administrator annually that you have complied with the evaporative cooling tower requirements specified in § 63.622(c).

(iii) Submit analyses and supporting documentation demonstrating conformance with the Office Of Air Quality Planning And Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance (incorporated by reference, see § 63.14) and specifications for bag leak detection systems as part of the notification of compliance status report.

(iv) If you elect to demonstrate compliance by following the procedures in § 63.625(d)(1)(ii)(B), certify to the Administrator annually that the control devices and processes have not been modified since the date of the performance test from which you obtained the data used to establish the allowable ranges.

(3) As required by § 63.10(e)(1), you must submit an excess emissions report for any exceedance of an emission or operating parameter limit if the total duration of the exceedances for the reporting period is 1 percent of the total operating time for the reporting period or greater. The report must contain the information specified in § 63.10 and paragraph (b)(4) of this section. When exceedances of an emission limit or operating parameter have not occurred, you must include such information in the report. You must submit the report semiannually and the report must be delivered or postmarked by the 30th day following the end of the calendar half. If exceedances are reported, you must submit the excess emissions report quarterly until a request to reduce reporting frequency is approved as described in § 63.10(e)(3).

(4) In the event that an affected unit fails to meet an applicable standard, record and report the following information for each failure:

(i) The date, time and duration of the failure.

(ii) A list of the affected sources or equipment for which a failure occurred.

(iii) An estimate of the volume of each regulated pollutant emitted over any emission limit.

(iv) A description of the method used to estimate the emissions.

(v) A record of actions taken to minimize emissions in accordance with § 63.628(b), and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

(5) You must submit a summary report containing the information specified in § 63.10(e)(3)(vi). You must submit the summary report semiannually and the report must be delivered or postmarked by the 30th day following the end of the calendar half.

(c) Your records must be in a form suitable and readily available for expeditious review. You must keep each record for 5 years following the date of each recorded action. You must keep each record on site, or accessible from a central location by computer or other means that instantly provide access at the site, for at least 2 years after the date of each recorded action. You may keep the records off site for the remaining 3 years.

(d) In computing averages to determine compliance with this subpart, you must exclude the monitoring data specified in paragraphs (d)(1) through (3) of this section.

(1) Periods of non-operation of the process unit;

(2) Periods of no flow to a control device; and

(3) Any monitoring data recorded during continuous parameter monitoring system (CPMS) breakdowns, out-of-control periods, repairs, maintenance periods, instrument adjustments or checks to maintain precision and accuracy, calibration checks, and zero (low-level), mid-level (if applicable), and high-level adjustments.

(e) Within 60 days after the date of completing each performance test (as defined in § 63.2) required by this subpart, you must submit the results of the performance tests, including any associated fuel analyses, following the procedure specified in either paragraph (e)(1) or (2) of this section.

(1) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*http://cdx.epa.gov/epa_home.asp*). Performance test data must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, you may submit performance test data in an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site once the XML schema is available. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(2) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

§ 63.628 General requirements and applicability of general provisions of this part.

(a) You must comply with the general provisions in subpart A of this part as specified in appendix A to this subpart.

(b) At all times, you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination by the Administrator of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c) For each CMS used to demonstrate compliance with any applicable emission limit, you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan according to the requirements specified in paragraphs (c)(1) through (3) of this section. You must submit the site-specific monitoring plan, if requested by the Administrator, at least 60 days before the initial performance evaluation of the CMS. The requirements of this paragraph also apply if a petition is made to the Administrator for alternative monitoring parameters under § 63.8(f).

(1) You must include the information specified in paragraphs (c)(1)(i) through (vi) of this section in the site-specific monitoring plan.

(i) Location of the CMS sampling probe or other interface. You must include a justification demonstrating that the sampling probe or other interface is at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.,* on or downstream of the last control device).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations).

(iv) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), (c)(4)(ii), and Table 4 to this subpart.

(v) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d)(1) and (2) and Table 5 to this subpart.

(vi) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1), (e)(2)(i).

(2) You must include a schedule for conducting initial and subsequent performance evaluations in the site-specific monitoring plan.

(3) You must keep the site-specific monitoring plan on site for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If you revise the site-specific monitoring plan, you must keep previous (*i.e.,* superseded) versions of the plan on site to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. You must include the program of corrective action required under § 63.8(d)(2) in the plan.

(d) For each bag leak detection system installed to comply with the requirements specified in § 63.625(e), you must include the information specified in paragraphs (d)(1) and (2) of this section in the site-specific monitoring plan specified in paragraph (c) of this section.

(1) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations), including how the alarm set-point will be established.

(2) A corrective action plan describing corrective actions to be taken and the timing of those actions when the bag leak detection alarm sounds. Corrective actions may include, but are not limited to, the actions specified in paragraphs (d)(2)(i) through (vi) of this section.

(i) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other conditions that may cause an increase in regulated material emissions.

(ii) Sealing off defective bags or filter media.

(iii) Replacing defective bags or filter media or otherwise repairing the control device.

(iv) Sealing off a defective fabric filter compartment.

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system.

(vi) Shutting down the process controlled by the fabric filter.

§ 63.629 Miscellaneous requirements.

The Administrator retains the authority to approve site-specific test plans for uncontrolled granular triple superphosphate storage buildings developed pursuant to § 63.7(c)(2)(i).

§ 63.630 [Reserved]

§ 63.631 Exemption from new source performance standards.

Any affected source subject to the provisions of this subpart is exempted from any otherwise applicable new source performance standard contained in 40 CFR part 60, subpart V, subpart W, or subpart X. To be exempt, a source must have a current operating permit pursuant to title V of the Clean Air Act and the source must be in compliance with all requirements of this subpart. For each affected source, this exemption is effective upon the date that you demonstrate to the Administrator that the requirements of §§ 63.625 and 63.626 have been met.

§ 63.632 Implementation and enforcement.

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as the applicable state, local, or Tribal agency. If the U.S. EPA Administrator has delegated authority to a state, local, or Tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a state, local, or Tribal agency.

(b) The authorities specified in paragraphs (b)(1) through (5) of this section are retained by the Administrator of U.S. EPA and cannot be delegated to State, local, or Tribal agencies.

(1) Approval of alternatives to the requirements in §§ 63.620, 63.622, 63.625, 63.629, and 63.631.

(2) Approval of requests under §§ 63.7(e)(2)(ii) and 63.7 (f) for alternative requirements or major changes to the test methods specified in this subpart, as defined in § 63.90.

(3) Approval of requests under § 63.8(f) for alternative requirements or major changes to the monitoring requirements specified in this subpart, as defined in § 63.90.

(4) Waiver or approval of requests under § 63.10(f) for alternative requirements or major changes to the recordkeeping and reporting requirements specified in this subpart, as defined in § 63.90.

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

TABLE 1 TO SUBPART BB OF PART 63—EXISTING SOURCE EMISSION LIMITS [a] [b]

For the following existing sources . . .	You must meet the emission limits for the specified pollutant . . .
	Total fluorides
Phosphate Fertilizer Process Line (*e.g.,* Diammonium and/or Monoammonium Phosphate Process Line).	0.060 lb/ton of equivalent P_2O_5 feed.
Granular Triple Superphosphate Process Line	0.150 lb/ton of equivalent P_2O_5 feed.
GTSP storage building	5.0×10^{-4} lb/hr/ton of equivalent P_2O_5 stored.

[a] The existing source compliance date is June 10, 2002.

[b] During periods of startup and shutdown, for emission limits stated in terms of pounds of pollutant per ton of feed, you are subject to the work practice standards specified in § 63.622(d).

Table 2 to Subpart BB of Part 63—New Source Emission Limits [a][b]

For the following new sources . . .	You must meet the emission limits for the specified pollutant . . .
	Total fluorides
Phosphate Fertilizer Process Line (*e.g.,* Diammonium and/or Monoammonium Phosphate Process Line).	0.0580 lb/ton of equivalent P_2O_5 feed.
Granular Triple Superphosphate Process Line	0.1230 lb/ton of equivalent P_2O_5 feed.
GTSP storage building	5.0×10^{-4} lb/hr/ton of equivalent P_2O_5 stored.

[a] The new source compliance dates are based on date of construction or reconstruction as specified in § 63.622(a).

[b] During periods of startup and shutdown, for emission limits stated in terms of pounds of pollutant per ton of feed, you are subject to the work practice standards specified in § 63.622(d).

Table 3 to Subpart BB of Part 63—Monitoring Equipment Operating Parameters

You must . . .	If . . .	And you must monitor . . .	And . . .
	Absorbers (Wet Scrubbers)		
Install a continuous parameter monitoring system (CPMS) for liquid flow at the inlet of the absorber..	Your absorber is designed and operated with pressure drops of 5 inches of water column or more; and you choose to monitor only the influent liquid flow, rather than the liquid-to-gas ratio.	Influent liquid flow.	
Install CPMS for liquid and gas flow at the inlet of the absorber.	Your absorber is designed and operated with pressure drops of 5 inches of water column or less; or. Your absorber is designed and operated with pressure drops of 5 inches of water column or more, and you choose to monitor the liquid-to-gas ratio, rather than only the influent liquid flow, and you want the ability to lower liquid flow with changes in gas flow.	Liquid-to-gas ratio as determined by dividing the influent liquid flow rate by the inlet gas flow rate. The units of measure must be consistent with those used to calculate this ratio during the performance test.	You must measure the gas stream by: Measuring the gas stream flow at the absorber inlet; or Using the design blower capacity, with appropriate adjustments for pressure drop.
Install CPMS for pressure at the gas stream inlet and outlet of the absorber.	Your absorber is designed and operated with pressure drops of 5 inches of water column or more.	Pressure drop through the absorber	You may measure the pressure of the inlet gas using amperage on the blower if a correlation between pressure and amperage is established.

Table 4 to Subpart BB of Part 63—Operating Parameters, Operating Limits and Data Monitoring, Recordkeeping and Compliance Frequencies

For the operating parameter applicable to you, as specified in Table 3 . . .	You must establish the following operating limit during your performance test . . .	And you must monitor, record, and demonstrate continuous compliance using these minimum frequencies	Data measurement	Data recording
		Absorbers (Wet Scrubbers)		
Influent liquid flow	Minimum inlet liquid flow	Continuous	Every 15 minutes	Daily.
Influent liquid flow rate and gas stream flow rate.	Minimum influent liquid-to-gas ratio.	Continuous	Every 15 minutes	Daily.
Pressure drop	Pressure drop range	Continuous	Every 15 minutes	Daily.

TABLE 5 TO SUBPART BB OF PART 63—CALIBRATION AND QUALITY CONTROL REQUIREMENTS FOR CONTINUOUS PARAMETER MONITORING SYSTEMS (CPMS)

If you monitor this parameter . . .	Your accuracy requirements are . . .	And your calibration requirements are . . .
Flow Rate	± 5 percent over the normal range of flow measured or 1.9 liters per minute (0.5 gallons per minute), whichever is greater, for liquid flow rate.. ± 5 percent over the normal range of flow measured or 28 liters per minute (10 cubic feet per minute), whichever is greater, for gas flow rate.. ± 5 percent over the normal range measured for mass flow rate..	Performance evaluation annually and following any period of more than 24 hours throughout which the flow rate exceeded the maximum rated flow rate of the sensor, or the data recorder was off scale. Checks of all mechanical connections for leakage monthly. Visual inspections and checks of CPMS operation every 3 months, unless the CPMS has a redundant flow sensor. Selection of a representative measurement location where swirling flow or abnormal velocity distributions due to upstream and downstream disturbances at the point of measurement are minimized.
Pressure	± 5 percent over the normal range measured or 0.12 kilopascals (0.5 inches of water column), whichever is greater..	Checks for obstructions (*e.g.,* pressure tap pluggage) at least once each process operating day. Performance evaluation annually and following any period of more than 24 hours throughout which the pressure exceeded the maximum rated pressure of the sensor, or the data recorder was off scale. Checks of all mechanical connections for leakage monthly. Visual inspection of all components for integrity, oxidation and galvanic corrosion every 3 months, unless the CPMS has a redundant pressure sensor. Selection of a representative measurement location that minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.

Appendix A to Subpart BB of Part 63—Applicability of General Provisions (40 CFR Part 63, Subpart A) to Subpart BB

40 CFR citation	Requirement	Applies to subpart BB	Comment
§ 63.1(a)(1) through (4)	General Applicability	Yes	None.
§ 63.1(a)(5)		No	[Reserved].
§ 63.1(a)(6)	Contact information	Yes	None.
§ 63.1(a)(7) through (9)		No	[Reserved].
§ 63.1(a)(10) through (12)	Time periods	Yes	None.
§ 63.1(b)	Initial Applicability Determination	Yes	None.
§ 63.1(c)(1)	Applicability After Standard Established.	Yes	None.
§ 63.1(c)(2)	Permits	Yes	Some plants may be area sources.
§ 63.1(c)(3) through (4)		No	[Reserved].
§ 63.1(c)(5)	Area to Major source change	Yes	None.
§ 63.1(d)		No	[Reserved].
§ 63.1(e)	Applicability of Permit Program	Yes	None.
§ 63.2	Definitions	Yes	Additional definitions in § 63.621.
§ 63.3	Units and Abbreviations	Yes	None.
§ 63.4(a)(1) and (2)	Prohibited Activities	Yes	None.
§ 63.4(a)(3) through (5)		No	[Reserved].
§ 63.4(b) and (c)	Circumvention/Fragmentation	Yes	None.
§ 63.5(a)	Construction/Reconstruction Applicability.	Yes	None.
§ 63.5(b)(1)	Existing, New, Reconstructed Sources Requirements.	Yes	None.
§ 63.5(b)(2)		No	[Reserved].
§ 63.5(b)(3), (4), and (6)	Construction/Reconstruction approval and notification.	Yes	None.
§ 63.5(b)(5)		No	[Reserved].
§ 63.5(c)		No	[Reserved].
§ 63.5(d)	Application for Approval of Construction/Reconstruction.	Yes	None.
§ 63.5(e)	Approval of Construction/Reconstruction.	Yes	None.
§ 63.5(f)	Approval of Construction/Reconstruction Based on State Review.	Yes	None.
§ 63.6(a)	Compliance with Standards and Maintenance Applicability.	Yes	None.

40 CFR citation	Requirement	Applies to subpart BB	Comment
§ 63.6(b)(1) through (5)	New and Reconstructed Sources Dates.	Yes	See also § 63.622.
§ 63.6(b)(6)		No	[Reserved].
§ 63.6(b)(7)	Area to major source change	Yes	None.
§ 63.6(c)(1) and (2)	Existing Sources Dates	Yes	§ 63.622 specifies dates.
§ 63.6(c)(3) and (4)		No	[Reserved].
§ 63.6(c)(5)	Area to major source change	Yes	None.
§ 63.6(d)		No	[Reserved].
§ 63.6(e)(1)(i) and (ii)	Operation & Maintenance Requirements.	No	See § 63.628(b) for general duty requirement.
§ 63.6(e)(iii)		Yes	None.
§ 63.6(e)(2)		No	[Reserved].
§ 63.6(e)(3)	Startup, Shutdown, and Malfunction Plan.	No	None.
§ 63.6(f)	Compliance with Emission Standards	No	See general duty at § 63.628(b).
§ 63.6(g)	Alternative Standard	Yes	None.
§ 63.6(h)	Compliance with Opacity/VE Standards.	No	Subpart BB does not include VE/opacity standards.
§ 63.6(i)(1) through (14)	Extension of Compliance	Yes	None.
§ 63.6(i)(15)		No	[Reserved].
§ 63.6(i)(16)		Yes	None.
§ 63.6(j)	Exemption from Compliance	Yes	None.
§ 63.7(a)	Performance Test Requirements Applicability.	Yes	None.
§ 63.7(b)	Notification	Yes	None.
§ 63.7(c)	Quality Assurance/Test Plan	Yes	None.
§ 63.7(d)	Testing Facilities	Yes	None.
§ 63.7(e)(1)	Conduct of Tests; startup, shutdown and malfunction provisions.	No	§ 63.626 specifies additional requirements.
§ 63.7(e)(2) through (4)	Conduct of Tests	Yes	§ 63.626 specifies additional requirements.
§ 63.7(f)	Alternative Test Method	Yes	None.
§ 63.7(g)	Data Analysis	Yes	None.
§ 63.7(h)	Waiver of Tests	Yes	None.
§ 63.8(a)	Monitoring Requirements Applicability.	Yes	None.
§ 63.8(b)	Conduct of Monitoring	Yes	None.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No	See § 63.628(b) for general duty requirement.
§ 63.8(c)(1)(ii)		Yes	None.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS.	No	None.
§ 63.8(c)(2) through (4)	CMS Operation/Maintenance	Yes	None.
§ 63.8(c)(5)	COMS Operation	No	Subpart BB does not require COMS.
§ 63.8(c)(6) through (8)	CMS requirements	Yes	None.
§ 63.8(d)(1) and (2)	Quality Control	Yes	None.
§ 63.8(d)(3)	Written procedure for CMS	No	See § 63.628 for requirement.
§ 63.8(e)	CMS Performance Evaluation	Yes	None.
§ 63.8(f)(1) through (5)	Alternative Monitoring Method	Yes	None.
§ 63.8(f)(6)	Alternative to RATA Test	No	Subpart BB does not require CEMS.
§ 63.8(g)(1)	Data Reduction	Yes	None.
§ 63.8(g)(2)		No	Subpart BB does not require COMS or CEMS.
§ 63.8(g)(3) through (5)		Yes	None.
§ 63.9(a)	Notification Requirements Applicability.	Yes	None.
§ 63.9(b)	Initial Notifications	Yes	None.
§ 63.9(c)	Request for Compliance Extension	Yes	None.
§ 63.9(d)	New Source Notification for Special Compliance Requirements.	Yes	None.
§ 63.9(e)	Notification of Performance Test	Yes	None.
§ 63.9(f)	Notification of VE/Opacity Test	No	Subpart BB does not include VE/opacity standards.
§ 63.9(g)	Additional CMS Notifications	Yes	None.
§ 63.9(h)(1) through (3)	Notification of Compliance Status	Yes	None.
§ 63.9(h)(4)		No	[Reserved].
§ 63.9(h)(5) and (6)		Yes	None.
§ 63.9(i)	Adjustment of Deadlines	Yes	None.
§ 63.9(j)	Change in Previous Information	Yes	None.
§ 63.10(a)	Recordkeeping/Reporting-Applicability.	Yes	None.
§ 63.10(b)(1)	General Recordkeeping Requirements.	Yes	None.
§ 63.10(b)(2)(i)	Startup or shutdown duration	No	None.

40 CFR citation	Requirement	Applies to subpart BB	Comment
§ 63.10(b)(2)(ii)	Malfunction	No	See § 63.627 for recordkeeping and reporting requirement.
§ 63.10(b)(2)(iii)	Maintenance records	Yes	None.
§ 63.10(b)(2)(iv) and (v)	Startup, shutdown, malfunction actions.	No	None.
§ 63.10(b)(2)(vi) through (xiv)	General Recordkeeping Requirements.	Yes	None.
§ 63.10(b)(3)	General Recordkeeping Requirements.	Yes	None.
§ 63.10(c)(1)	Additional CMS Recordkeeping	Yes	None.
§ 63.10(c)(2) through (4)		No	[Reserved].
§ 63.10(c)(5)		Yes	None.
§ 63.10(c)(6)		Yes	None.
§ 63.10(c)(7) and (8)		Yes	None.
§ 63.10(c)(9)		No	[Reserved].
§ 63.10(c)(10) through (13)		Yes	None.
§ 63.10(c)(14)		Yes	None.
§ 63.10(c)(15)	Startup Shutdown Malfunction Plan Provisions.	No	None.
§ 63.10(d)(1)	General Reporting Requirements	Yes	None.
§ 63.10(d)(2)	Performance Test Results	Yes	None.
§ 63.10(d)(3)	Opacity or VE Observations	No	Subpart BB does not include VE/opacity standards.
§ 63.10(d)(4)	Progress Reports	Yes	None.
§ 63.10(d)(5)	Startup, Shutdown, and Malfunction Reports.	No	See § 63.627 for reporting of excess emissions.
§ 63.10(e)(1) and (2)	Additional CMS Reports	Yes	None.
§ 63.10(e)(3)	Excess Emissions/CMS Performance Reports.	Yes	None.
§ 63.10(e)(4)	COMS Data Reports	No	Subpart BB does not require COMS.
§ 63.10(f)	Recordkeeping/Reporting Waiver	Yes	None.
§ 63.11	Control Device and Work Practice Requirements.	Yes	None.
§ 63.12	State Authority and Delegations	Yes	None.
§ 63.13	Addresses	Yes	None.
§ 63.14	Incorporation by Reference	Yes	None.
§ 63.15	Information Availability/Confidentiality	Yes	None.
§ 63.16	Performance Track Provisions	No	Terminated.

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Part II

Environmental Protection Agency

40 CFR Parts 60, 70, 71, et al.

Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60, 70, 71, and 98

[EPA–HQ–OAR–2013–0495; EPA–HQ–OAR–2013–0603; FRL–9930–66–OAR]

RIN 2060–AQ91

Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing new source performance standards (NSPS) under Clean Air Act (CAA) section 111(b) that, for the first time, will establish standards for emissions of carbon dioxide (CO_2) for newly constructed, modified, and reconstructed affected fossil fuel-fired electric utility generating units (EGUs). This action establishes separate standards of performance for fossil fuel-fired electric utility steam generating units and fossil fuel-fired stationary combustion turbines. This action also addresses related permitting and reporting issues. In a separate action, under CAA section 111(d), the EPA is issuing final emission guidelines for states to use in developing plans to limit CO_2 emissions from existing fossil fuel-fired EGUs.

DATES: This final rule is effective on October 23, 2015. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of October 23, 2015.

ADDRESSES: The EPA has established dockets for this action under Docket ID No. EPA–HQ–OAR–2013–0495 (Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units) and Docket ID No. EPA–HQ–OAR–2013–0603 (Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units). All documents in the dockets are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center (EPA/DC), Room 3334, EPA WJC West Building, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Dr. Nick Hutson, Energy Strategies Group, Sector Policies and Programs Division (D243–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541–2968, facsimile number (919) 541–5450; email address: *hutson.nick@epa.gov* or Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (D243–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541–4003, facsimile number (919) 541–5450; email address: *fellner.christian@epa.gov.*

SUPPLEMENTARY INFORMATION: *Acronyms.* A number of acronyms and chemical symbols are used in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined as follows:

AB	Assembly Bill
AEO	Annual Energy Outlook
AEP	American Electric Power
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
BACT	Best Available Control Technology
BDT	Best Demonstrated Technology
BSER	Best System of Emission Reduction
Btu/kWh	British Thermal Units per Kilowatt-hour
Btu/lb	British Thermal Units per Pound
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CBI	Confidential Business Information
CCS	Carbon Capture and Storage (or Sequestration)
CDX	Central Data Exchange
CEDRI	Compliance and Emissions Data Reporting Interface
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CH_4	Methane
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
DOE	Department of Energy
DOT	Department of Transportation
ECMPS	Emissions Collection and Monitoring Plan System
EERS	Energy Efficiency Resource Standards
EGU	Electric Generating Unit
EIA	Energy Information Administration
EO	Executive Order
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
FB	Fluidized Bed
FGD	Flue Gas Desulfurization
FOAK	First-of-a-kind
FR	Federal Register
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GPM	Gallons per Minute
GS	Geologic Sequestration
GW	Gigawatts
H_2	Hydrogen Gas
HAP	Hazardous Air Pollutant
HFC	Hydrofluorocarbon
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
IPM	Integrated Planning Model
IRPs	Integrated Resource Plans
kg/MWh	Kilogram per Megawatt-hour
kJ/kg	Kilojoules per Kilogram
kWh	Kilowatt-hour
lb CO_2/MMBtu	Pounds of CO_2 per Million British Thermal Unit
lb CO_2/MWh	Pounds of CO_2 per Megawatt-hour
lb CO_2/yr	Pounds of CO_2 per Year
lb/lb-mole	Pounds per Pound-Mole
LCOE	Levelized Cost of Electricity
MATS	Mercury and Air Toxic Standards
MMBtu/hr	Million British Thermal Units per Hour
MRV	Monitoring, Reporting, and Verification
MW	Megawatt
MWe	Megawatt Electrical
MWh	Megawatt-hour
MWh-g	Megawatt-hour gross
MWh-n	Megawatt-hour net
N_2O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NAS	National Academy of Sciences
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NOAK	n^{th}-of-a-kind
NRC	National Research Council
NSPS	New Source Performance Standards
NSR	New Source Review
NTTAA	National Technology Transfer and Advancement Act
O_2	Oxygen Gas
OMB	Office of Management and Budget
PC	Pulverized Coal
PFC	Perfluorocarbon
PM	Particulate Matter
$PM_{2.5}$	Fine Particulate Matter
PRA	Paperwork Reduction Act
PSD	Prevention of Significant Deterioration
PUC	Public Utilities Commission
RCRA	Resource Conservation and Recovery Act
RFA	Regulatory Flexibility Act
RGGI	Regional Greenhouse Gas Initiative
RIA	Regulatory Impact Analysis
RPS	Renewable Portfolio Standard
RTC	Response to Comments
RTP	Response to Petitions
SBA	Small Business Administration
SCC	Social Cost of Carbon
SCR	Selective Catalytic Reduction
SCPC	Supercritical Pulverized Coal
SDWA	Safe Drinking Water Act
SF_6	Sulfur Hexafluoride
SIP	State Implementation Plan

SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction
Tg	Teragram (one trillion (10^{12}) grams)
Tpy	Tons per Year
TSD	Technical Support Document
TTN	Technology Transfer Network
UIC	Underground Injection Control
UMRA	Unfunded Mandates Reform Act of 1995
U.S.	United States
USDW	Underground Source of Drinking Water
USGCRP	U.S. Global Change Research Program
VCS	Voluntary Consensus Standard
WGS	Water Gas Shift
WWW	World Wide Web

Organization of This Document. The information presented in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

In this final action the EPA is establishing standards that limit greenhouse gas (GHG) emissions from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units and stationary combustion turbines, following the issuance of proposals for such standards and an accompanying Notice of Data Availability.

On June 25, 2013, in conjunction with the announcement of his Climate Action Plan (CAP), President Obama issued a

Presidential Memorandum directing the EPA to issue a proposal to address carbon pollution from new power plants by September 30, 2013, and to issue ''standards, regulations, or guidelines, as appropriate, which address carbon pollution from modified, reconstructed, and existing power plants.'' Pursuant to authority in section 111(b) of the CAA, on September 20, 2013, the EPA issued proposed carbon pollution standards for newly constructed fossil fuel-fired power plants. The proposal was published in the **Federal Register** on January 8, 2014 (79 FR 1430; ''January 2014 proposal'').[1] In that proposal, the EPA proposed to limit emissions of CO_2 from newly constructed fossil fuel-fired electric utility steam generating units and newly constructed natural gas-fired stationary combustion turbines.

The EPA subsequently issued a Notice of Data Availability (NODA) in which the EPA solicited comment on its initial interpretation of provisions in the Energy Policy Act of 2005 (EPAct05) and associated provisions in the Internal Revenue Code (IRC) and also solicited comment on a companion Technical Support Document (TSD) that addressed these provisions' relationship to the factual record supporting the proposed rule. 79 FR 10750 (February 26, 2014).

On June 2, 2014, the EPA proposed standards of performance, also pursuant to CAA section 111(b), to limit emissions of CO_2 from modified and reconstructed fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines. 79 FR 34960 (June 18, 2014) (''June 2014 proposal''). Specifically, the EPA proposed standards of performance for: (1) Modified fossil fuel-fired steam generating units, (2) modified natural gas-fired stationary combustion turbines, (3) reconstructed fossil fuel-fired steam generating units, and (4) reconstructed natural gas-fired stationary combustion turbines.

In this action, the EPA is issuing final standards of performance to limit emissions of GHG pollution manifested as CO_2 from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units (*i.e.,* utility boilers and integrated gasification combined cycle (IGCC) units) and from newly constructed and reconstructed stationary combustion turbines. Consistent with the requirements of CAA section 111(b), these standards reflect the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) that the EPA has determined has been adequately demonstrated for each type of unit. These final standards are codified in 40 CFR part 60, subpart TTTT, a new subpart specifically created for CAA 111(b) standards of performance for GHG emissions from fossil fuel-fired EGUs.

In a separate action that affects the same source category, the EPA is issuing final emission guidelines under CAA section 111(d) for states to use in developing plans to limit CO_2 emissions from existing fossil fuel-fired EGUs. Pursuant to those guidelines, states must submit plans to the EPA following a schedule set by the guidelines.

The EPA received numerous comments and conducted extensive outreach to stakeholders for this rulemaking. After careful consideration of public comments and input from a variety of stakeholders, the final standards of performance in this action reflect certain changes from the proposals. Comments considered include written comments that were submitted during the public comment period and oral testimony provided during the public hearing for the proposed standards.

2. Summary of Major Provisions and Changes to the Proposed Standards

The BSER determinations and final standards of performance for affected newly constructed, modified, and reconstructed EGUs are summarized in Table 1 and discussed in more detail below. The final standards for new, modified, and reconstructed EGUs apply to sources that commenced construction—or modification or reconstruction, as appropriate—on or after the date of publication of corresponding proposed standards.[2] The final standards for newly constructed fossil fuel-fired EGUs apply to those sources that commenced construction on or after the date of publication of the proposed standards, January 8, 2014. The final standards for modified and reconstructed fossil fuel-fired EGUs apply to those sources that modify or reconstruct on or after the date of publication of the proposed standards, June 18, 2014.

TABLE 1—SUMMARY OF BSER AND FINAL STANDARDS FOR AFFECTED EGUS

Affected EGUs	BSER	Final standards of performance
Newly Constructed Fossil Fuel-Fired Steam Generating Units.	Efficient new supercritical pulverized coal (SCPC) utility boiler implementing partial carbon capture and storage (CCS).	1,400 lb CO_2/MWh-g.
Modified Fossil Fuel-Fired Steam Generating Units.	Most efficient generation at the affected EGU achievable through a combination of best operating practices and equipment upgrades.	Sources making modifications resulting in an increase in CO_2 hourly emissions of more than 10 percent are required to meet a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than: 1. 1,800 lb CO_2/MWh-g for sources with heat input >2,000 MMBtu/h. 2. 2,000 lb CO_2/MWh-g for sources with heat input ≤2,000 MMBtu/h.
Reconstructed Fossil Fuel-Fired Steam Generating Units.	Most efficient generating technology at the affected source (supercritical steam conditions for the larger; and subcritical conditions for the smaller).	1. Sources with heat input >2,000 MMBtu/h are required to meet an emission limit of 1,800 lb CO_2/MWh-g. 2. Sources with heat input ≤2,000 MMBtu/h are required to meet an emission limit of 2,000 lb CO_2/MWh-g.

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[1] The EPA previously proposed performance standards for newly reconstructed fossil fuel-fired EGUs in April 2012 (77 FR 22392). In that action, the EPA proposed standards for steam generating units and natural gas-fired combustion turbines based on a single Best System of Emission Reduction determination. On January 8, 2014, the EPA withdrew that proposal (79 FR 1352).

[2] See CAA section 111(a)(2).

TABLE 1—SUMMARY OF BSER AND FINAL STANDARDS FOR AFFECTED EGUS—Continued

Affected EGUs	BSER	Final standards of performance
Newly Constructed and Reconstructed Fossil Fuel-Fired Stationary Combustion Turbines.	Efficient NGCC technology for base load natural gas-fired units and clean fuels for non-base load and multi-fuel-fired units.[3]	1. 1,000 lb CO_2/MWh-g or 1,030 lb CO_2/MWh-n for base load natural gas-fired units. 2. 120 lb CO_2/MMBtu for non-base load natural gas-fired units. 3. 120 to 160 lb CO_2/MMBtu for multi-fuel-fired units.[4]

a. Fossil Fuel-Fired Electric Utility Steam Generating Units

This action establishes standards of performance for newly constructed fossil fuel-fired steam generating units[5] based on the performance of a new highly efficient SCPC EGU implementing post-combustion partial carbon capture and storage (CCS) technology, which the EPA determines to be the BSER for these sources. After consideration of a wide range of comments, technical input received on the availability, technical feasibility, and cost of CCS implementation, and publicly available information about projects that are implementing or planning to implement CCS, the EPA confirms its proposed determination that CCS technology is available and technically feasible to implement at fossil fuel-fired steam generating units. However, the EPA's final standard reflects the consideration of legitimate concerns regarding the cost to implement available CCS technology on a new steam generating unit. Accordingly, the EPA is finalizing an emission standard for newly constructed fossil fuel-fired steam generating units at 1,400 lb CO_2/MWh-g, a level that is less stringent than the proposed limitation of 1,100 lb CO_2/MWh-g. This final standard reflects our identification of the BSER for such units to be a lower level of partial CCS than we identified as the basis of the proposed standards—one that we conclude better represents the requirement that the BSER be implementable at reasonable cost.

The EPA proposed that the BSER for newly constructed steam generating EGUs was highly efficient new generating technology (*i.e.,* a supercritical utility boiler or IGCC unit) implementing partial CCS technology to achieve CO_2 emission reductions resulting in an emission limit of 1,100 lb CO_2/MWh-g.[6]

The BSER for newly constructed steam generating EGUs in the final rule is very similar to that in the January 2014 proposal. In this final action, the EPA finds that a highly efficient new supercritical pulverized coal (SCPC) utility boiler EGU implementing partial CCS to the degree necessary to achieve an emission of 1,400 lb CO_2/MWh-g is the BSER. Contrary to the January 2014 proposal, the EPA finds that IGCC technology—either with natural gas co-firing or implementing partial CCS—is not part of the BSER, but recognizes that IGCC technology can serve as an alternative method of compliance.

The EPA finds that a highly efficient SCPC implementing partial CCS is the BSER because CCS technology has been demonstrated to be technically feasible and is in use or under construction in various industrial sectors, including the power generation sector. For example, the Boundary Dam Unit #3 CCS project in Saskatchewan, Canada is a full-scale, fully integrated CCS project that is currently operating and is designed to capture more than 90 percent of the CO_2 from the lignite-fired boiler. A newly constructed, highly efficient SCPC utility boiler burning bituminous coal will be able to meet this final standard of performance by capturing and storing approximately 16 percent of the CO_2 produced from the facility. A newly constructed, highly efficient SCPC utility boiler burning subbituminous coal or dried lignite[7] will be able to meet this final standard of performance by capturing and storing approximately 23 percent of the CO_2 produced from the facility. As an alternative compliance option, utilities and project developers will also be able to construct new steam generating units (both utility boilers and IGCC units) that meet the final standard of performance by co-firing with natural gas. This final standard of performance for newly constructed fossil fuel-fired steam generating units provides a clear and achievable path forward for the construction of such sources while addressing GHG emissions and supporting technological innovation. The standard of 1,400 lb CO_2/MWh-g is achievable by fossil fuel-fired steam generating units for all fuel types, under a wide range of conditions, and throughout the United States.

We note that identifying a highly efficient new SCPC EGU implementing partial CCS as the BSER provides a path forward for new fossil fuel-fired steam generation in the current market context. Numerous studies have predicted that few new fossil fuel-fired steam generating units will be constructed in the future. These analyses identify a range of factors unrelated to this rulemaking, including low electricity demand growth, highly competitive natural gas prices, and increases in the supply of renewable energy. The EPA recognizes that, in certain circumstances, there may be interest in building fossil fuel-fired steam generating units despite these market conditions. In particular, utilities and project developers may build new fossil fuel-fired steam generating EGUs in order to achieve or maintain fuel diversity within generating fleets, as a hedge against the possibility of natural gas prices far exceeding projections, or to co-produce both power and chemicals, including capturing CO_2 for use in enhanced oil

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[3] The term ''multi-fuel-fired'' refers to a stationary combustion turbine that is physically connected to a natural gas pipeline, but that burns a fuel other than natural gas for 10 percent or more of the unit's heat input capacity during the 12-operating-month compliance period.

[4] The emission standard for combustion turbines co-firing natural gas with other fuels shall be determined at the end of each operating month based on the amount of co-fired natural gas. Units only burning natural gas with other fuels with a relatively consistent chemical composition and an emission factor of 160 lb CO_2/MMBtu or less (*e.g.,* natural gas, distillate oil, etc.) only need to maintain records of the fuels burned at the unit to demonstrate compliance. Units burning fuels with variable chemical composition or with an emission factor greater than 160 lb CO_2/MMBtu (*e.g.,* residual oil) must conduct periodic fuel sampling and testing to determine the overall CO_2 emission rate.

[5] Also referred to as just ''steam generating units'' or as ''utility boilers and IGCC units''. These are units that are covered under 40 CFR part 60, subpart Da for criteria pollutants.

[6] Using the most recent data on partial capture rates to meet an emission standard of 1,100 lb CO_2/MWh-gross, about 35 percent capture would be required at an SCPC unit and about 22 percent capture would be required at an IGCC unit.

[7] For a summary of lignite drying technologies, see ''Techno-economics of modern pre-drying technologies for lignite-fired power plants'' available at *www.iea-coal.org.uk/documents/83436/9095/Techno-economics-of-modern-pre-drying-technologies-for-lignite-fired-power-plants,-CCC/241*; ''Drying the lignite prior to combustion in the boiler is thus an effective way to increase the thermal efficiencies and reduce the CO_2 emissions from lignite-fired power plants.''

recovery (EOR) projects.[8] As regulatory history has shown, identifying a new highly efficient SCPC EGU implementing partial CCS as the BSER in this rule is likely to further boost research and development in CCS technologies, making the implementation even more efficacious and cost-effective, while providing a competitive, low emission future for fossil fuel-fired steam generation.

The EPA is also issuing final standards for steam generating units that implement ''large modifications,'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent when compared to the source's highest hourly emissions in the previous 5 years).[9] The EPA is not issuing final standards, at this time, for steam generating units that implement ''small modifications'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of less than or equal to 10 percent when compared to the source's highest hourly emissions in the previous 5 years).

The standards of performance for modified steam generating units that make large modifications are based on each affected unit's own best potential performance as the BSER. Specifically, such a modified steam generating unit will be required to meet a unit-specific CO_2 emission limit determined by that unit's best demonstrated historical performance (in the years from 2002 to the time of the modification).[10] The EPA has determined that this standard based on each unit's own best potential performance can be met through a combination of best operating practices and equipment upgrades and that these steps can be implemented cost-effectively at the time when a source is undertaking a large modification. To account for facilities that have already implemented best practices and equipment upgrades, the final rule also specifies that modified facilities will not have to meet an emission standard more stringent than the corresponding standard for reconstructed steam generating units (*i.e.,* 1,800 lb CO_2/MWh-g for units with heat input greater than 2,000 MMBtu/h and 2,000 lb CO_2/MWh-g for units with heat input less than or equal to 2,000 MMBtu/h).

The final standards for steam generating units implementing large modifications are similar to the proposed standards for such units. In the proposal, we suggested that the standard should be based on when the modification is undertaken (*i.e.,* before being subject to requirements under a CAA section 111(d) state plan or after being subject to such a plan). We also suggested that for units that undertake modifications prior to becoming subject to an approved CAA section 111(d) state plan, the standard should be its best historical performance plus an additional two percent reduction. In response to comments on the proposal, we are not finalizing separate standards that are dependent upon when the modification takes place, nor are we finalizing the proposed additional two percentage reduction.

The EPA is not promulgating final standards of performance for, and is withdrawing the proposed standards for steam generating sources that make modifications resulting in an increase of hourly CO_2 emissions of less than or equal to 10 percent (see Section XV of this preamble). As we indicated in the proposal, the EPA has been notified of very few modifications for criteria pollutant emissions from the power sector to which NSPS requirements have applied. As such, we expect that there will be few NSPS modifications for GHG emissions as well. Even so, we also recognize (and we discuss in this preamble) that the power sector is undergoing significant change and realignment in response to a variety of influences and incentives in the industry. We do not have sufficient information at this time, however, to anticipate the types of modifications, if any, that may result from these changes. In particular, we do not have sufficient information about the types of modifications, if any, that would result in increases in CO_2 emissions of 10 percent or less, and what the appropriate standard for such sources would be. Therefore, we conclude that it is prudent to delay issuing standards for sources that undertake small modifications (*i.e.,* those resulting in an increase in CO_2 emissions of less than or equal to 10 percent).

For reconstructed steam generating units, the EPA is finalizing standards based on the performance of the most efficient generating technology for these types of units as the BSER (*i.e.,* reconstructing the boiler if necessary to use steam with higher temperature and pressure, even if the boiler was not originally designed to do so).[11] The emission standard for these sources is 1,800 lb CO_2/MWh-g for large sources, (*i.e.* those with a heat input rating of greater than 2,000 MMBtu/h) or 2,000 lb CO_2/MWh-g for small sources (*i.e.,* those with a heat input rating of 2,000 MMBtu/h or less). The difference in the standards for larger and smaller units is based on greater availability of higher pressure/temperature steam turbines (*e.g.,* supercritical steam turbines) for larger units. The standards can also be met through other non-BSER options, such as natural gas co-firing.

b. Stationary Combustion Turbines

This action also finalizes standards of performance for newly constructed and reconstructed stationary combustion turbines. In the January 2014 proposal for newly constructed EGUs, the EPA proposed that natural gas-fired stationary combustion turbines (*i.e.,* turbines combusting over 90 percent natural gas) would be subject to a standard of performance for CO_2 emissions if they are constructed for the purpose of supplying and actually annually supply to the grid (1) one-third or more of their potential electric output[12] and (2) more than 219,000 MWh,[13] based on a three-year rolling average. We refer to units that operate above the electric sales thresholds as ''base load units,'' and we refer to units that operate below these thresholds as ''non-base load units.''

In the January 2014 proposal for newly constructed combustion turbines, the EPA proposed standards for two subcategories of base load natural gas-fired stationary combustion turbines. The proposed standard for small combustion turbines (units with base load ratings less than or equal to 850 MMBtu/h) was 1,100 lb CO_2/MWh-g. The proposed standard for large combustion turbines (units with base

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[8] As the EIA has stated: Policy-related factors, such as environmental regulations and investment or production tax credits for specified generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future policies may cause plant owners or investors who finance plants to place a value on *portfolio diversification.* While EIA considers many of these factors in its analysis of technology choice in the electricity sector, these concepts are not included in LCOE or LACE calculations. *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[9] 40 CFR 60.14(h) provides that no physical change, or change in the method of operation, at an existing electric utility steam generating unit will be treated as a modification provided that such change does not increase the maximum hourly emissions above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

[10] For the 2002 reporting year the EPA introduced new automated checks in the software that integrated automated quality assurance (QA) checks on the hourly data. Thus, the EPA believes that the data from 2002 and forward are of higher quality.

[11] Steam with higher temperature and pressure has more thermal energy that can be more efficiently converted to electrical energy.

[12] We refer to thresholds related to an EGU's actual annual electrical sales (as a fraction of potential annual output) as ''percentage electric sales criteria.''

[13] We refer to thresholds related to an EGU's actual annual electrical sales in megawatt-hours as ''total electric sales criteria.''

load ratings greater than 850 MMBtu/h) was 1,000 lb CO_2/MWh-g. The EPA did not propose standards for non-base load units.

In the June 2014 proposal for modified and reconstructed combustion turbines, the EPA solicited comment on alternative approaches for establishing applicability and subcategorization criteria, including (1) eliminating the ‘‘constructed for the purpose of supplying’’ qualifier for the total electric sales and percentage electric sales criteria, (2) eliminating the 219,000 MWh total electric sales criterion altogether, (3) replacing the fixed percentage electric sales criterion with a variable percentage electric sales criterion (*i.e.,* the sliding-scale approach[14]), and (4) eliminating the proposed small and large subcategories for base load natural gas-fired combustion turbines. These proposed applicability requirements were intended to exclude combustion turbines that are used for the purpose of meeting peak power demand, as opposed to those that are used to meet base load power demand.

In both proposals, the EPA also solicited comment on a broad applicability approach that would include non-base load natural gas-fired units (primarily simple cycle combustion turbines) and multi-fuel-fired units (primarily distillate oil-fired combustion turbines) in the general applicability of subpart TTTT. As part of the broad applicability approach, the EPA solicited comment on imposing ‘‘no emission standard’’ or establishing separate numerical limits for these two subcategories.

In this action, the EPA is finalizing a variation of the approaches put forward in the January 2014 proposal for new sources and the June 2014 proposal for modified and reconstructed sources. Based on our review of public comments related to the proposed subcategories for small and large combustion turbines and our additional data analyses, we have determined that there is no need to set two separate standards for different sizes of combustion turbines for base load natural gas-fired combustion turbines. The EPA has determined that all sizes of affected newly constructed and reconstructed stationary combustion turbines can achieve the final standards. For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, the EPA is finalizing a standard of 1,000 lb CO_2/MWh-g based on efficient natural gas combined cycled (NGCC) technology as the BSER. Alternatively, owners and operators of base load natural gas-fired combustion turbines may elect to comply with a standard based on net output of 1,030 lb CO_2/MWh-n.

The EPA is eliminating the 219,000 MWh total annual electric sales criterion for non-CHP units. In addition, the EPA is finalizing the sliding-scale approach for deriving the unit-specific, percentage electric sales threshold above which a combustion turbine transitions from the subcategory for non-base load units to the subcategory for base load units. For newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines, the EPA is finalizing the combustion of clean fuels (natural gas with a small allowance for distillate oil) as the BSER with a corresponding heat input-based standard of 120 lb CO_2/MMBtu. This standard of performance will apply to the vast majority of simple cycle combustion turbines. The EPA is finalizing a heat input-based clean fuels standard because we have insufficient information at this time to set a uniform output-based standard that can be achieved by all new and reconstructed non-base load units.

In addition, for newly constructed and reconstructed multi-fuel-fired stationary combustion turbines, the EPA is finalizing an input-based standard of 120 to 160 lb CO_2/MMBtu based on the combustion of clean fuels as the BSER.[15] The EPA has similarly determined that it has insufficient information at this time to set a uniform output-based standard for stationary combustion turbines that operate with significant quantities of a fuel other than natural gas.

We are not promulgating final standards of performance for stationary combustion turbines that make modifications at this time. We are simultaneously withdrawing the proposed standards for modifications (see Section XV of this preamble). As we indicated in the proposal, sources from the power sector have notified the EPA of very few NSPS modifications, and we expect that there will be few NSPS modifications for CO_2 emissions as well. Moreover, our decision to eliminate the subcategories for small and large EGUs and set a single standard of 1,000 lb CO_2/MWh-g has raised questions as to whether smaller existing combustion turbines that undertake a modification can meet this standard. As a result, we have concluded that it is prudent to delay issuing standards for sources that undertake modifications until we can gather more information.

A more detailed discussion of the final standards of performance for stationary combustion turbines, the applicability criteria, and the comments that influenced the final standards is provided in Sections VIII and IX of this preamble.

3. Costs and Benefits

As explained in the regulatory impact analysis (RIA) for this final rule, available data—including utility announcements and Energy Information Administration (EIA) modeling—indicate that, even in the absence of this rule, (i) existing and anticipated economic conditions are such that few, if any, fossil fuel-fired steam-generating EGUs will be built in the foreseeable future, and (ii) utilities and project developers are expected to choose new generation technologies (primarily NGCC) that would meet the final standards and renewable generating sources that are not affected by these final standards. These projections are consistent with utility announcements and EIA modeling that indicate that new units are likely to be NGCC and that any coal-fired steam generating units built between now and 2030 would have CCS, even in the absence of this rule.[16] Therefore, based on the analysis presented in Chapter 4 of the RIA, the EPA projects that this final rule will result in negligible CO_2 emission changes, quantified benefits, and costs by 2022 as a result of the performance standards for newly constructed EGUs.[17] However, as noted earlier, for a variety of reasons, some companies may consider coal-fired steam generating units that the modeling does not anticipate. Thus, in Chapter 5 of the RIA, we also present an analysis of the project-level costs of a newly constructed coal-fired steam generating unit with partial CCS that meets the requirements of this final rule alongside the project-level costs of a newly constructed coal-fired unit without CCS. This analysis indicates that the

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[14] The sliding-scale approach determines a unit-specific percentage electric sales threshold equivalent to a unit's net design efficiency (the maximum value is capped at 50 percent).

[15] Combustion turbines co-firing natural gas with other fuels shall determine fuel-based site-specific standards at the end of each operating month. The site-specific standards depend on the amount of co-fired natural gas.

[16] The EPA's Integrated Planning Model (IPM) projects no new non-compliant coal (*i.e.,* newly constructed coal-fired plants that do not meet the final standard of performance) throughout the model horizon of 2030 (there is a small amount of new coal with CCS that is hardwired into the modelling, consistent with EIA assumptions to represent units already under construction or under development).

[17] Conditions in the analysis year of 2022 are represented by a model year of 2020.

quantified benefits of the standards of performance would exceed their costs under a range of assumptions.

As explained in the RIA and further below, the EPA has been notified of few power sector NSPS modifications or reconstructions. Based on that experience, the EPA expects that few EGUs will trigger either the modification or the reconstruction provisions that we are finalizing in this action. In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

B. Does this action apply to me?

The entities potentially affected by the standards are shown in Table 2 below.

TABLE 2—POTENTIALLY AFFECTED ENTITIES [a]

Category	NAICS code	Examples of potentially affected entities
Industry	221112	Fossil fuel electric power generating units.
Federal Government	[b]221112	Fossil fuel electric power generating units owned by the federal government.
State/Local Government	[b]221112	Fossil fuel electric power generating units owned by municipalities.
Tribal Government	921150	Fossil fuel electric power generating units in Indian Country.

[a] Includes NAICS categories for source categories that own and operate electric power generating units (including boilers and stationary combined cycle combustion turbines).

[b] Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by this action. To determine whether your facility, company, business, organization, etc., would be regulated by this action, refer to Section III of this preamble for more information and examine the applicability criteria in 40 CFR 60.1 (General Provisions) and § 60.550840 of subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units). If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

C. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this final action will also be available on the Worldwide Web (WWW). Following signature, a copy of this final action will be posted at the following address: *http://www2.epa.gov/carbon-pollution-standards.*

D. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by December 22, 2015. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements. Section 307(d)(7)(B) of the CAA 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 mandating the EPA to convene a proceeding for reconsideration if the person raising an objection can demonstrate 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 should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios 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. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

E. How is this preamble organized?

This action presents the EPA's final standards of performance for newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units and newly constructed and reconstructed stationary combustion turbines. Section II provides background information on climate change impacts from GHG emissions, GHG emissions from fossil fuel-fired EGUs, the utility power sector, the statutory and regulatory background relating to CAA section 111(b), EPA actions prior to this final action, and public comments regarding the proposed actions. Section III explains the EPA's authority to regulate CO_2 and EGUs, identifies affected EGUs, and describes the source categories. Section IV provides a summary of the final standards for newly constructed, modified, and reconstructed fossil fuel-fired steam generating units. Sections V through VII present the rationale for the final standards for newly constructed, modified, and reconstructed steam generating units, respectively. Sections VIII and IX provide a summary of the final standards for stationary combustion turbines and present the rationale for the final standards for newly constructed and reconstructed combustion turbines, respectively. Section X provides a summary of other final requirements for newly constructed, modified, and reconstructed fossil fuel-fired steam generating units and stationary combustion turbines. Section XI addresses the consistency of the respective BSER determinations in these rules and under the emission guidelines issued separately under CAA section 111(d). Interactions with other EPA programs and rules are described in Section XII. Projected impacts of the final action are then described in Section XIII, followed by a discussion of statutory and executive order reviews in Section XIV. Section XV addresses the withdrawal of the proposed standards for steam generating EGUs that make modifications resulting in an increase of hourly CO_2 emissions of less than or equal to 10 percent and the proposed standards for modified stationary combustion turbines. The statutory authority for this action is provided in Section XVI. We address major comments throughout this preamble and in greater detail in an accompanying response-to-comments document located in the docket.

II. Background

In this section, we discuss climate change impacts from GHG emissions, both on public health and public welfare. We also present information about GHG emissions from fossil fuel-fired EGUs and describe the utility power sector and its changing structure. We then summarize the statutory and regulatory background relevant to this final rulemaking. In addition, we provide background information on the EPA's January 8, 2014 proposed carbon pollution standards for newly constructed fossil fuel-fired EGUs, the June 18, 2014 proposed carbon pollution standards for modified and reconstructed EGUs, and other actions associated with this final rulemaking. We close this section with a general discussion of comments and stakeholder input that the EPA received prior to issuing this final rulemaking.

A. Climate Change Impacts From GHG Emissions

According to the National Research Council, ''Emissions of CO_2 from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth's climate. Because CO_2 in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe. Therefore, emission reduction choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia.'' [18]

In 2009, based on a large body of robust and compelling scientific evidence, the EPA Administrator issued the Endangerment Finding under CAA section 202(a)(1).[19] In the Endangerment Finding, the Administrator found that the current, elevated concentrations of GHGs in the atmosphere—already at levels unprecedented in human history—may reasonably be anticipated to endanger public health and welfare of current and future generations in the United States. We summarize these adverse effects on public health and welfare briefly here.

1. Public Health Impacts Detailed in the 2009 Endangerment Finding

Climate change caused by human emissions of GHGs threatens the health of Americans in multiple ways. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the United States. Compared to a future without climate change, climate change is expected to increase ozone pollution over broad areas of the U.S., especially on the highest ozone days and in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Climate change is also expected to cause more intense hurricanes and more frequent and intense storms and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

2. Public Welfare Impacts Detailed in the 2009 Endangerment Finding

Climate change impacts touch nearly every aspect of public welfare. Among the multiple threats caused by human emissions of GHGs, climate changes are expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to face a multitude of increased risks, particularly from rising sea level and increases in the severity of storms. These communities face storm and flood damage to property, or even loss of land due to inundation, erosion, wetland submergence and habitat loss.

Impacts of climate change on public welfare also include threats to social and ecosystem services. Climate change is expected to result in an increase in peak electricity demand. Extreme weather from climate change threatens energy, transportation, and water resource infrastructure. Climate change may also exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities, and is very likely to fundamentally rearrange U.S. ecosystems over the 21st century. Though some benefits may balance adverse effects on agriculture and forestry in the next few decades, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture and forest productivity as temperature continues to rise. These impacts are global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S.

3. New Scientific Assessments and Observations

Since the administrative record concerning the Endangerment Finding closed following the EPA's 2010 Reconsideration Denial, the climate has continued to change, with new records being set for a number of climate indicators such as global average surface temperatures, Arctic sea ice retreat, CO_2 concentrations, and sea level rise. Additionally, a number of major scientific assessments have been released that improve understanding of the climate system and strengthen the case that GHGs endanger public health and welfare both for current and future generations. These assessments, from the Intergovernmental Panel on Climate Change (IPCC), the U.S. Global Change Research Program (USGCRP), and the National Research Council (NRC), include: IPCC's 2012 *Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation* (SREX) and the 2013–2014 Fifth Assessment Report (AR5), the USGCRP's 2014 National Climate Assessment, *Climate Change Impacts in the United States* (NCA3), and the NRC's 2010 *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean* (Ocean Acidification), 2011 *Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia* (Climate Stabilization Targets), 2011 *National Security Implications for U.S. Naval Forces* (National Security Implications), 2011 *Understanding Earth's Deep Past: Lessons for Our Climate Future* (Understanding Earth's Deep Past), 2012 *Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future,* 2012 *Climate and Social Stress: Implications for Security Analysis* (Climate and Social Stress), and 2013 *Abrupt Impacts of Climate Change* (Abrupt Impacts) assessments.

The EPA has carefully reviewed these recent assessments in keeping with the same approach outlined in Section III.A of the 2009 Endangerment Finding, which was to rely primarily upon the major assessments by the USGCRP, the IPCC, and the NRC of the National Academies to provide the technical and scientific information to inform the Administrator's judgment regarding the question of whether GHGs endanger public health and welfare. These

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[18] National Research Council, Climate Stabilization Targets, p. 3.

[19] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' 74 FR 66496 (Dec. 15, 2009) (''Endangerment Finding'').

assessments addressed the scientific issues that the EPA was required to examine, were comprehensive in their coverage of the GHG and climate change issues, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S. government review.

The findings of the recent scientific assessments confirm and strengthen the conclusion that GHGs endanger public health, now and in the future. The NCA3 indicates that human health in the United States will be impacted by ''increased extreme weather events, wildfire, decreased air quality, threats to mental health, and illnesses transmitted by food, water, and disease-carriers such as mosquitoes and ticks.'' The most recent assessments now have greater confidence that climate change will influence production of pollen that exacerbates asthma and other allergic respiratory diseases such as allergic rhinitis, as well as effects on conjunctivitis and dermatitis. Both the NCA3 and the IPCC AR5 found that increasing temperature has lengthened the allergenic pollen season for ragweed, and that increased CO_2 by itself can elevate production of plant-based allergens.

The NCA3 also finds that climate change, in addition to chronic stresses such as extreme poverty, is negatively affecting indigenous peoples' health in the United States through impacts such as reduced access to traditional foods, decreased water quality, and increasing exposure to health and safety hazards. The IPCC AR5 finds that climate change-induced warming in the Arctic and resultant changes in environment (*e.g.,* permafrost thaw, effects on traditional food sources) have significant impacts, observed now and projected, on the health and well-being of Arctic residents, especially indigenous peoples. Small, remote, predominantly-indigenous communities are especially vulnerable given their ''strong dependence on the environment for food, culture, and way of life; their political and economic marginalization; existing social, health, and poverty disparities; as well as their frequent close proximity to exposed locations along ocean, lake, or river shorelines.'' [20] In addition, increasing temperatures and loss of Arctic sea ice increases the risk of drowning for those engaged in traditional hunting and fishing.

The NCA3 concludes that children's unique physiology and developing bodies contribute to making them particularly vulnerable to climate change. Impacts on children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. The IPCC AR5 indicates that children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. The IPCC finds that additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

Both the NCA3 and IPCC AR5 conclude that climate change will increase health risks facing the elderly. Older people are at much higher risk of mortality during extreme heat events. Pre-existing health conditions also make older adults susceptible to cardiac and respiratory impacts of air pollution and to more severe consequences from infectious and waterborne diseases. Limited mobility among older adults can also increase health risks associated with extreme weather and floods.

The new assessments also confirm and strengthen the conclusion that GHGs endanger public welfare, and emphasize the urgency of reducing GHG emissions due to their projections that show GHG concentrations climbing to ever-increasing levels in the absence of mitigation. The NRC assessment, *Understanding Earth's Deep Past,* projected that, without a reduction in emissions, CO_2 concentrations by the end of the century would increase to levels that the Earth has not experienced for more than 30 million years.[21] In fact, that assessment stated that ''the magnitude and rate of the present greenhouse gas increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history.'' [22] Because of these unprecedented changes, several assessments state that we may be approaching critical, poorly understood thresholds. As stated in the assessment, ''As Earth continues to warm, it may be approaching a critical climate threshold beyond which rapid and potentially permanent—at least on a human timescale—changes not anticipated by climate models tuned to modern conditions may occur.'' The NRC *Abrupt Impacts* report analyzed abrupt climate change in the physical climate system and abrupt impacts of ongoing changes that, when thresholds are crossed, can cause abrupt impacts for society and ecosystems. The report considered destabilization of the West Antarctic Ice Sheet (which could cause 3–4 m of potential sea level rise) as an abrupt climate impact with unknown but probably low probability of occurring this century. The report categorized a decrease in ocean oxygen content (with attendant threats to aerobic marine life); increase in intensity, frequency, and duration of heat waves; and increase in frequency and intensity of extreme precipitation events (droughts, floods, hurricanes, and major storms) as climate impacts with moderate risk of an abrupt change within this century. The NRC *Abrupt Impacts* report also analyzed the threat of rapid state changes in ecosystems and species extinctions as examples of irreversible impacts that are expected to be exacerbated by climate change. Species at most risk include those whose migration potential is limited, whether because they live on mountaintops or fragmented habitats with barriers to movement, or because climatic conditions are changing more rapidly than the species can move or adapt. While the NRC determined that it is not presently possible to place exact probabilities on the added contribution of climate change to extinction, they did find that there was substantial risk that impacts from climate change could, within a few decades, drop the populations in many species below sustainable levels, thereby committing the species to extinction. Species within tropical and subtropical rainforests such as the Amazon and species living in coral reef ecosystems were identified by the NRC as being particularly vulnerable to extinction over the next 30 to 80 years, as were species in high latitude and high elevation regions. Moreover, due to the time lags inherent in the Earth's climate, the NRC *Climate Stabilization Targets* assessment notes that the full warming from any given concentration of CO_2 reached will not be fully realized for several centuries, underscoring that emission activities today carry with them climate commitments far into the future.

Future temperature changes will depend on what emission path the world follows. In its high emission scenario, the IPCC AR5 projects that

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[20] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, p. 1581.

[21] National Research Council, Understanding Earth's Deep Past, p. 1.

[22] *Id.*, p. 138.

average global temperatures by the end of the century will likely be 2.6 degrees Celsius (°C) to 4.8 °C (4.7 to 8.6 degrees Fahrenheit (°F)) warmer than today. Temperatures on land and in northern latitudes will likely warm even faster than the global average. However, according to the NCA3, significant reductions in emissions would lead to noticeably less future warming beyond mid-century, and therefore less impact to public health and welfare.

While rainfall may only see small globally and annually averaged changes, there are expected to be substantial shifts in where and when that precipitation falls. According to the NCA3, regions closer to the poles will see more precipitation, while the dry subtropics are expected to expand (colloquially, this has been summarized as wet areas getting wetter and dry regions getting drier). In particular, the NCA3 notes that the western U.S., and especially the Southwest, is expected to become drier. This projection is consistent with the recent observed drought trend in the West. At the time of publication of the NCA, even before the last 2 years of extreme drought in California, tree ring data was already indicating that the region might be experiencing its driest period in 800 years. Similarly, the NCA3 projects that heavy downpours are expected to increase in many regions, with precipitation events in general becoming less frequent but more intense. This trend has already been observed in regions such as the Midwest, Northeast, and upper Great Plains. Meanwhile, the NRC Climate Stabilization Targets assessment found that the area burned by wildfire is expected to grow by 2 to 4 times for 1 °C (1.8 °F) of warming. For 3 °C of warming, the assessment found that 9 out of 10 summers would be warmer than all but the 5 percent of warmest summers today, leading to increased frequency, duration, and intensity of heat waves. Extrapolations by the NCA also indicate that Arctic sea ice in summer may essentially disappear by mid-century. Retreating snow and ice, and emissions of CO_2 and methane released from thawing permafrost, will also amplify future warming.

Since the 2009 Endangerment Finding, the USGCRP NCA3, and multiple NRC assessments have projected future rates of sea level rise that are 40 percent larger to more than twice as large as the previous estimates from the 2007 IPCC 4th Assessment Report due in part to improved understanding of the future rate of melt of the Antarctic and Greenland Ice sheets. The NRC *Sea Level Rise* assessment projects a global sea level rise of 0.5 to 1.4 meters (1.6 to 4.6 feet) by 2100, the NRC *National Security Implications* assessment suggests that ''the Department of the Navy should expect roughly 0.4 to 2 meters (1.3 to 6.6 feet) global average sea-level rise by 2100,'' [23] and the NRC *Climate Stabilization Targets* assessment states that an increase of 3 °C will lead to a sea level rise of 0.5 to 1 meter (1.6 to 3.3 feet) by 2100. These assessments continue to recognize that there is uncertainty inherent in accounting for ice sheet processes. Additionally, local sea level rise can differ from the global total depending on various factors. The east coast of the U.S. in particular is expected to see higher rates of sea level rise than the global average. For comparison, the NCA3 states that ''five million Americans and hundreds of billions of dollars of property are located in areas that are less than four feet above the local high-tide level,'' and the NCA3 finds that ''[c]oastal infrastructure, including roads, rail lines, energy infrastructure, airports, port facilities, and military bases, are increasingly at risk from sea level rise and damaging storm surges.'' [24] Also, because of the inertia of the oceans, sea level rise will continue for centuries after GHG concentrations have stabilized (though more slowly than it would have otherwise). Additionally, there is a threshold temperature above which the Greenland ice sheet will be committed to inevitable melting. According to the NCA, some recent research has suggested that even present day CO_2 levels could be sufficient to exceed that threshold.

In general, climate change impacts are expected to be unevenly distributed across different regions of the United States and have a greater impact on certain populations, such as indigenous peoples and the poor. The NCA3 finds that climate change impacts such as the rapid pace of temperature rise, coastal erosion and inundation related to sea level rise and storms, ice and snow melt, and permafrost thaw are affecting indigenous people in the U.S. Particularly in Alaska, critical infrastructure and traditional livelihoods are threatened by climate change and, ''[i]n parts of Alaska, Louisiana, the Pacific Islands, and other coastal locations, climate change impacts (through erosion and inundation) are so severe that some communities are already relocating from historical homelands to which their traditions and cultural identities are tied.'' [25] The IPCC AR5 notes, ''Climate-related hazards exacerbate other stressors, often with negative outcomes for livelihoods, especially for people living in poverty (high confidence). Climate-related hazards affect poor people's lives directly through impacts on livelihoods, reductions in crop yields, or destruction of homes and indirectly through, for example, increased food prices and food insecurity.'' [26]

CO_2 in particular has unique impacts on ocean ecosystems. The NRC *Climate Stabilization Targets* assessment found that coral bleaching will increase due both to warming and ocean acidification. Ocean surface waters have already become 30 percent more acidic over the past 250 years due to absorption of CO_2 from the atmosphere. According to the NCA3, this acidification will reduce the ability of organisms such as corals, krill, oysters, clams, and crabs to survive, grow, and reproduce. The NRC *Understanding Earth's Deep Past* assessment notes that four of the five major coral reef crises of the past 500 million years were caused by acidification and warming that followed GHG increases of similar magnitude to the emissions increases expected over the next hundred years. The NRC *Abrupt Impacts* assessment specifically highlighted similarities between the projections for future acidification and warming and the extinction at the end of the Permian which resulted in the loss of an estimated 90 percent of known species. Similarly, the NRC *Ocean Acidification* assessment finds that ''[t]he chemistry of the ocean is changing at an unprecedented rate and magnitude due to anthropogenic CO_2 emissions; the rate of change exceeds any known to have occurred for at least the past

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[23] NRC, 2011: *National Security Implications of Climate Change for U.S. Naval Forces.* The National Academies Press, p. 28.

[24] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, p. 9.

[25] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, p. 17.

[26] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, p. 796.

hundreds of thousands of years.'' [27] The assessment notes that the full range of consequences is still unknown, but the risks ''threaten coral reefs, fisheries, protected species, and other natural resources of value to society.'' [28]

Events outside the United States, as also pointed out in the 2009 Endangerment Finding, will also have relevant consequences. The NRC *Climate and Social Stress* assessment concluded that it is prudent to expect that some climate events ''will produce consequences that exceed the capacity of the affected societies or global systems to manage and that have global security implications serious enough to compel international response.'' The NRC *National Security Implications* assessment recommends preparing for increased needs for humanitarian aid; responding to the effects of climate change in geopolitical hotspots, including possible mass migrations; and addressing changing security needs in the Arctic as sea ice retreats.

In addition to future impacts, the NCA3 emphasizes that climate change driven by human emissions of GHGs is already happening now and it is happening in the United States. According to the IPCC AR5 and the NCA3, there are a number of climate-related changes that have been observed recently, and these changes are projected to accelerate in the future. The planet warmed about 0.85 °C (1.5 °F) from 1880 to 2012. It is extremely likely (>95 percent probability) that human influence was the dominant cause of the observed warming since the mid-20th century, and likely (>66 percent probability) that human influence has more than doubled the probability of occurrence of heat waves in some locations. In the Northern Hemisphere, the last 30 years were likely the warmest 30-year period of the last 1400 years. U.S. average temperatures have similarly increased by 1.3 to 1.9 °F since 1895, with most of that increase occurring since 1970. Global sea levels rose 0.19 m (7.5 inches) from 1901 to 2010. Contributing to this rise was the warming of the oceans and melting of land ice. It is likely that 275 gigatons per year of ice have melted from land glaciers (not including ice sheets) since 1993, and that the rate of loss of ice from the Greenland and Antarctic ice sheets has increased substantially in recent years, to 215 gigatons per year and 147 gigatons per year respectively, since 2002. For context, 360 gigatons of ice melt is sufficient to cause global sea levels to rise 1 mm. Annual mean Arctic sea ice has been declining at 3.5 to 4.1 percent per decade, and Northern Hemisphere snow cover extent has decreased at about 1.6 percent per decade for March and 11.7 percent per decade for June. Permafrost temperatures have increased in most regions since the 1980s, by up to 3 °C (5.4 °F) in parts of Northern Alaska. Winter storm frequency and intensity have both increased in the Northern Hemisphere. The NCA3 states that the increases in the severity or frequency of some types of extreme weather and climate events in recent decades can affect energy production and delivery, causing supply disruptions, and compromise other essential infrastructure such as water and transportation systems.

In addition to the changes documented in the assessment literature, there have been other climate milestones of note. In 2009, the year of the Endangerment Finding, the average concentration of CO_2 as measured on top of Mauna Loa was 387 parts per million, far above preindustrial concentrations of about 280 parts per million.[29] The average concentration in 2013, the last full year before this rule was proposed, was 396 parts per million. The average concentration in 2014 was 399 parts per million. And the monthly concentration in April of 2014 was 401 parts per million, the first time a monthly average has exceeded 400 parts per million since record keeping began at Mauna Loa in 1958, and for at least the past 800,000 years based on ice core records.[30] Arctic sea ice has continued to decline, with September of 2012 marking a new record low in terms of Arctic sea ice extent, 40 percent below the 1979–2000 median. Sea level has continued to rise at a rate of 3.2 mm per year (1.3 inches/decade) since satellite observations started in 1993, more than twice the average rate of rise in the 20th century prior to 1993.[31] And 2014 was the warmest year globally in the modern global surface temperature record, going back to 1880; this now means 19 of the 20 warmest years have occurred in the past 20 years, and except for 1998, the ten warmest years on record have occurred since 2002.[32] The first months of 2015 have also been some of the warmest on record.

These assessments and observed changes make it clear that reducing emissions of GHGs across the globe is necessary in order to avoid the worst impacts of climate change, and underscore the urgency of reducing emissions now. The NRC Committee on America's Climate Choices listed a number of reasons ''why it is imprudent to delay actions that at least begin the process of substantially reducing emissions.'' [33] For example:

- The faster emissions are reduced, the lower the risks posed by climate change. Delays in reducing emissions could commit the planet to a wide range of adverse impacts, especially if the sensitivity of the climate to greenhouse gases is on the higher end of the estimated range.
- Waiting for unacceptable impacts to occur before taking action is imprudent because the effects of greenhouse gas emissions do not fully manifest themselves for decades and, once manifest, many of these changes will persist for hundreds or even thousands of years.
- In the committee's judgment, the risks associated with doing business as usual are a much greater concern than the risks associated with engaging in strong response efforts.

4. Observed and Projected U.S. Regional Changes

The NCA3 assessed the climate impacts in eight regions of the United States, noting that changes in physical climate parameters such as temperatures, precipitation, and sea ice retreat were already having impacts on forests, water supplies, ecosystems, flooding, heat waves, and air quality. Moreover, the NCA3 found that future warming is projected to be much larger than recent observed variations in temperature, with precipitation likely to increase in the northern states, decrease in the southern states, and with the heaviest precipitation events projected to increase everywhere.

In the Northeast, temperatures increased almost 2 °F from 1895 to 2011, precipitation increased by about 5 inches (10 percent), and sea level rise of about a foot has led to an increase in coastal flooding. The 70 percent increase in the amount of rainfall falling in the 1 percent of the most intense events is a larger increase in extreme precipitation than experienced in any other U.S. region.

In the future, if emissions continue increasing, the Northeast is expected to experience 4.5 to 10 °F of warming by

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[27] NRC, 2010: *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean.* The National Academies Press, p. 5.

[28] *Id.*

[29] *ftp://aftp.cmdl.noaa.gov/products/trends/co2/co2_annmean_mlo.txt.*

[30] *http://www.esrl.noaa.gov/gmd/ccgg/trends/.*

[31] Blunden, J., and D. S. Arndt, Eds., 2014: State of the Climate in 2013. Bull. Amer. Meteor. Soc., 95 (7), S1–S238.

[32] *http://www.ncdc.noaa.gov/sotc/global/2014/13.*

[33] NRC, 2011: *America's Climate Choices,* The National Academies Press.

the 2080s. This will lead to more heat waves, coastal and river flooding, and intense precipitation events. The southern portion of the region is projected to see 60 additional days per year above 90 °F by mid-century. Sea levels in the Northeast are expected to increase faster than the global average because of subsidence, and changing ocean currents may further increase the rate of sea level rise. Specific vulnerabilities highlighted by the NCA include large urban populations particularly vulnerable to climate-related heat waves and poor air quality episodes, prevalence of climate sensitive vector-borne diseases like Lyme and West Nile Virus, usage of combined sewer systems that may lead to untreated water being released into local water bodies after climate-related heavy precipitation events, and 1.6 million people living within the 100-year coastal flood zone who are expected to experience more frequent floods due to sea level rise and tropical-storm induced storm-surge. The NCA also highlighted infrastructure vulnerable to inundation in coastal metropolitan areas, potential agricultural impacts from increased rain in the spring delaying planting or damaging crops or increased heat in the summer leading to decreased yields and increased water demand, and shifts in ecosystems leading to declines in iconic species in some regions, such as cod and lobster south of Cape Cod.

In the Southeast, average annual temperature during the last century cycled between warm and cool periods. A warm peak occurred during the 1930s and 1940s, followed by a cool period, and temperatures then increased again from 1970 to the present by an average of 2 °F. There have been increasing numbers of days above 95 °F and nights above 75 °F, and decreasing numbers of extremely cold days since 1970. Daily and five-day rainfall intensities have also increased, and summers have been either increasingly dry or extremely wet. Louisiana has already lost 1,880 square miles of land in the last 80 years due to sea level rise and other contributing factors.

The Southeast is exceptionally vulnerable to sea level rise, extreme heat events, hurricanes, and decreased water availability. Major consequences of further warming include significant increases in the number of hot days (95 °F or above) and decreases in freezing events, as well as exacerbated ground-level ozone in urban areas. Although projected warming for some parts of the region by the year 2100 is generally smaller than for other regions of the United States, projected warming for interior states of the region is larger than coastal regions by 1 °F to 2 °F. Projections further suggest that there will be fewer tropical storms globally, but that they will be more intense, with more Category 4 and 5 storms. The NCA identified New Orleans, Miami, Tampa, Charleston, and Virginia Beach as being specific cities that are at risk due to sea level rise, with homes and infrastructure increasingly prone to flooding. Additional impacts of sea level rise are expected for coastal highways, wetlands, fresh water supplies, and energy infrastructure.

In the Northwest, temperatures increased by about 1.3 °F between 1895 and 2011. A small average increase in precipitation was observed over this time period. However, warming temperatures have caused increased rainfall relative to snowfall, which has altered water availability from snowpack across parts of the region. Snowpack in the Northwest is an important freshwater source for the region. More precipitation falling as rain instead of snow has reduced the snowpack, and warmer springs have corresponded to earlier snowpack melting and reduced streamflows during summer months. Drier conditions have increased the extent of wildfires in the region.

Average annual temperatures are projected to increase by 3.3 °F to 9.7 °F by the end of the century (depending on future global GHG emissions), with the greatest warming expected during the summer. Continued increases in global GHG emissions are projected to result in up to a 30 percent decrease in summer precipitation. Earlier snowpack melt and lower summer stream flows are expected by the end of the century and will affect drinking water supplies, agriculture, ecosystems, and hydropower production. Warmer waters are expected to increase disease and mortality in important fish species, including Chinook and sockeye salmon. Ocean acidification also threatens species such as oysters, with the Northwest coastal waters already being some of the most acidified worldwide due to coastal upwelling and other local factors. Forest pests are expected to spread and wildfires to burn larger areas. Other high-elevation ecosystems are projected to be lost because they can no longer survive the climatic conditions. Low lying coastal areas, including the cities of Seattle and Olympia, will experience heightened risks of sea level rise, erosion, seawater inundation and damage to infrastructure and coastal ecosystems.

In Alaska, temperatures have changed faster than anywhere else in the United States. Annual temperatures increased by about 3 °F in the past 60 years. Warming in the winter has been even greater, rising by an average of 6 °F. Arctic sea ice is thinning and shrinking in area, with the summer minimum ice extent now covering only half the area it did when satellite records began in 1979. Glaciers in Alaska are melting at some of the fastest rates on Earth. Permafrost soils are also warming and beginning to thaw. Drier conditions have contributed to more large wildfires in the last 10 years than in any previous decade since the 1940s, when recordkeeping began. Climate change impacts are harming the health, safety, and livelihoods of Native Alaskan communities.

By the end of this century, continued increases in GHG emissions are expected to increase temperatures by 10 to 12 °F in the northernmost parts of Alaska, by 8 to 10 °F in the interior, and by 6 to 8 °F across the rest of the state. These increases will exacerbate ongoing arctic sea ice loss, glacial melt, permafrost thaw and increased wildfire, and threaten humans, ecosystems, and infrastructure. Precipitation is expected to increase to varying degrees across the state. However, warmer air temperatures and a longer growing season are expected to result in drier conditions. Native Alaskans are expected to experience declines in economically, nutritionally, and culturally important wildlife and plant species. Health threats will also increase, including loss of clean water, saltwater intrusion, sewage contamination from thawing permafrost, and northward extension of diseases. Wildfires will increasingly pose threats to human health as a result of smoke and direct contact. Areas underlain by ice-rich permafrost across the state are likely to experience ground subsidence and extensive damage to infrastructure as the permafrost thaws. Important ecosystems will continue to be affected. Surface waters and wetlands that are drying provide breeding habitat for millions of waterfowl and shorebirds that winter in the lower 48 states. Warmer ocean temperatures, acidification, and declining sea ice will contribute to changes in the location and availability of commercially and culturally important marine fish.

In the Southwest, temperatures are now about 2 °F higher than the past century, and are already the warmest that region has experienced in at least 600 years. The NCA notes that there is evidence that climate change-induced warming on top of recent drought has influenced tree mortality, wildfire frequency and area, and forest insect outbreaks. Sea levels have risen about 7 or 8 inches in this region, contributing to inundation of Highway 101 and back up of seawater into sewage systems in the San Francisco area.

Projections indicate that the Southwest will warm an additional 5.5 to 9.5 °F over the next century if emissions continue to increase. Winter snowpack in the Southwest is projected to decline (consistent with the record lows from this past winter), reducing the reliability of surface water supplies for cities, agriculture, cooling for power plants, and ecosystems. Sea level rise along the California coast will worsen coastal erosion, increase flooding risk for coastal highways, bridges, and low-lying airports, pose a threat to groundwater supplies in coastal cities such as Los Angeles, and increase vulnerability to floods for hundreds of thousands of residents in coastal areas. Climate change will also have impacts on the high-value specialty crops grown in the region as a drier climate will increase demands for irrigation, more frequent heat waves will reduce yields, and decreased winter chills may impair fruit and nut production for trees in California. Increased drought, higher temperatures, and bark beetle outbreaks are likely to contribute to continued increases in wildfires. The highly urbanized population of the Southwest is vulnerable to heat waves and water supply disruptions, which can be exacerbated in cases where high use of air conditioning triggers energy system failures.

The rate of warming in the Midwest has markedly accelerated over the past few decades. Temperatures rose by more than 1.5 °F from 1900 to 2010, but between 1980 and 2010, the rate of warming was three times faster than from 1900 through 2010. Precipitation generally increased over the last century, with much of the increase driven by intensification of the heaviest rainfalls. Several types of extreme weather events in the Midwest (*e.g.,* heat waves and flooding) have already increased in frequency and/or intensity due to climate change.

In the future, if emissions continue increasing, the Midwest is expected to experience 5.6 to 8.5 °F of warming by the 2080s, leading to more heat waves. Though projections of changes in total precipitation vary across the regions, more precipitation is expected to fall in the form of heavy downpours across the entire region, leading to an increase in flooding. Specific vulnerabilities highlighted by the NCA include long-term decreases in agricultural productivity, changes in the composition of the region's forests, increased public health threats from heat waves and degraded air and water quality, negative impacts on transportation and other infrastructure associated with extreme rainfall events and flooding, and risks to the Great Lakes including shifts in invasive species, increases in harmful algal blooms, and declining beach health.

High temperatures (more than 100 °F in the Southern Plains and more than 95 °F in the Northern Plains) are projected to occur much more frequently by mid-century. Increases in extreme heat will increase heat stress for residents, energy demand for air conditioning, and water losses. North Dakota's increase in annual temperatures over the past 130 years is the fastest in the contiguous U.S., mainly driven by warming winters. Specific vulnerabilities highlighted by the NCA include increased demand for water and energy, changes to crop-growth cycles and agricultural practices, and negative impacts on local plant and animal species from habitat fragmentation, wildfires, and changes in the timing of flowering or pest patterns. Communities that are already the most vulnerable to weather and climate extremes will be stressed even further by more frequent extreme events occurring within an already highly variable climate system.

In Hawaii, other Pacific islands, and the Caribbean, rising air and ocean temperatures, shifting rainfall patterns, changing frequencies and intensities of storms and drought, decreasing baseflow in streams, rising sea levels, and changing ocean chemistry will affect ecosystems on land and in the oceans, as well as local communities, livelihoods, and cultures. Low islands are particularly at risk.

Rising sea levels, coupled with high water levels caused by tropical and extra-tropical storms, will incrementally increase coastal flooding and erosion, damaging coastal ecosystems, infrastructure, and agriculture, and negatively affecting tourism. Ocean temperatures in the Pacific region exhibit strong year-to-year and decadal fluctuations, but since the 1950s, they have exhibited a warming trend, with temperatures from the surface to a depth of 660 feet rising by as much as 3.6 °F. As a result of current sea level rise, the coastline of Puerto Rico around Rincón is being eroded at a rate of 3.3 feet per year. Freshwater supplies are already constrained and will become more limited on many islands. Saltwater intrusion associated with sea level rise will reduce the quantity and quality of freshwater in coastal aquifers, especially on low islands. In areas where precipitation does not increase, freshwater supplies will be adversely affected as air temperature rises.

Warmer oceans are leading to increased coral bleaching events and disease outbreaks in coral reefs, as well as changed distribution patterns of tuna fisheries. Ocean acidification will reduce coral growth and health. Warming and acidification, combined with existing stresses, will strongly affect coral-reef fish communities. For Hawaii and the Pacific islands, future sea surface temperatures are projected to increase 2.3 °F by 2055 and 4.7 °F by 2090 under a scenario that assumes continued increases in emissions. Ocean acidification is also taking place in the region, which adds to ecosystem stress from increasing temperatures. Ocean acidity has increased by about 30 percent since the pre-industrial era and is projected to further increase by 37 percent to 50 percent from present levels by 2100.

The NCA also discussed impacts that occur along the coasts and in the oceans adjacent to many regions, and noted that other impacts occur across regions and landscapes in ways that do not follow political boundaries.

B. GHG Emissions From Fossil Fuel-Fired EGUs

Fossil fuel-fired EGUs are by far the largest emitters of GHGs among stationary sources in the U.S., primarily in the form of CO_2. Among fossil fuel-fired EGUs, coal-fired units are by far the largest emitters. This section describes the amounts of these emissions and places these amounts in the context of the U.S. Inventory of Greenhouse Gas Emissions and Sinks[34] (the U.S. GHG Inventory).

The EPA implements a separate program under 40 CFR part 98 called the Greenhouse Gas Reporting Program[35] (GHGRP) that requires emitting facilities that emit over certain threshold amounts of GHGs to report their emissions to the EPA annually. Using data from the GHGRP, this section also places emissions from fossil fuel-fired EGUs in the context of the total emissions reported to the GHGRP from facilities in the other largest-emitting industries.

The EPA prepares the official U.S. GHG Inventory to comply with commitments under the United Nations Framework Convention on Climate

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[34] "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013", Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html*.

[35] U.S. EPA Greenhouse Gas Reporting Program Dataset, see *http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html.*

Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sector. It provides the information in Table 3 below, which presents total U.S. anthropogenic emissions and sinks [36] of GHGs, including CO_2 emissions, for the years 1990, 2005 and 2013.

TABLE 3—U.S. GHG EMISSIONS AND SINKS BY SECTOR (MILLION METRIC TONS CARBON DIOXIDE EQUIVALENT (MMT CO_2e)) [37] [38]

Sector	1990	2005	2013
Energy [39]	5,290.5	6,273.6	5,636.6
Industrial Processes and Product Use	342.1	367.4	359.1
Agriculture	448.7	494.5	515.7
Land Use, Land-Use Change and Forestry	13.8	25.5	23.3
Waste	206.0	189.2	138.3
Total Emissions	6,301.1	7,350.2	6,673.0
Land Use, Land-Use Change and Forestry (Sinks)	(775.8)	(911.9)	(881.7)
Net Emissions (Sources and Sinks)	5,525.2	6,438.3	5,791.2

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.3 percent of total 2013 GHG emissions.[40] In 2013, fossil fuel combustion by the utility power sector—entities that burn fossil fuel and whose primary business is the generation of electricity—accounted for 38.3 percent of all energy-related CO_2 emissions.[41] Table 4 below presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005, and 2013.

TABLE 4—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS (MMT CO_2) [42]

GHG emissions	1990	2005	2013
Total CO_2 from fossil fuel-fired EGUs	1,820.8	2,400.9	2,039.8
—from coal	1,547.6	1,983.8	1,575.0
—from natural gas	175.3	318.8	441.9
—from petroleum	97.5	97.9	22.4

In addition to preparing the official U.S. GHG Inventory to present comprehensive total U.S. GHG emissions and comply with commitments under the UNFCCC, the EPA collects detailed GHG emissions data from the largest emitting facilities in the U.S. through its GHGRP. Data collected by the GHGRP from large stationary sources in the industrial sector show that the utility power sector emits far greater CO_2 emissions than any other industrial sector. Table 5 below presents total GHG emissions in 2013 for the largest emitting industrial sectors as reported to the GHGRP. As shown in Table 4 and Table 5, respectively, CO_2 emissions from fossil fuel-fired EGUs are nearly three times as large as the total reported GHG emissions from the next ten largest emitting industrial sectors in the GHGRP database combined.

TABLE 5—DIRECT GHG EMISSIONS REPORTED TO GHGRP BY LARGEST EMITTING INDUSTRIAL SECTORS (MMT CO_2e) [43]

Industrial sector	2013
Fossil Fuel-Fired EGUs	2,039.8
Petroleum Refineries	176.7
Onshore Oil & Gas Production	94.8
Municipal Solid Waste Landfills	93.0
Iron & Steel Production	84.2
Cement Production	62.8
Natural Gas Processing Plants	59.0
Petrochemical Production	52.7
Hydrogen Production	41.9
Underground Coal Mines	39.8
Food Processing Facilities	30.8

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[36] Sinks are physical units or processes that store GHGs, such as forests or underground or deep sea reservoirs of CO_2.

[37] From Table ES–4 of ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[38] 1 metric ton (tonne) is equivalent to 1,000 kilograms (kg) and is equivalent to 1.1023 short tons or 2,204.62 pounds (lb).

[39] The energy sector includes all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions.

[40] From Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[41] From Table 3–1 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[42] From Table 3–5 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[43] U.S. EPA Greenhouse Gas Reporting Program Dataset as of August 18, 2014. *http://ghgdata.epa.gov/ghgp/main.do.*

It should be noted that the discussion above concerned all fossil fuel-fired EGUs. Steam generators emitted 1,627 MMT CO_2e and combustion turbines emitted 401 MMT CO_2e in 2013.[44]

C. The Utility Power Sector

1. Modern Electric System Trends

The EPA includes a background discussion of the electricity system in the Clean Power Plan (CPP) rulemaking, which is the companion rulemaking to this rule that promulgates emission guidelines for states to use in regulating emissions of CO_2 from existing fossil fuel-fired EGUs. Readers are referred to that rulemaking. The following discussion of electricity sector trends is of particular relevance for this rulemaking.

The electricity sector is undergoing a period of intense change. Fossil fuels—such as coal, natural gas, and oil—have historically provided a large percentage of electricity in the U.S., with smaller amounts being provided by other types of generation, including nuclear and renewables such as wind, solar, and hydroelectric power. Coal has historically provided the largest percentage of fossil-fuel generation.[45] In recent years, the nation has seen a sizeable increase in renewable generation such as wind and solar, as well as a shift from coal to natural gas.[46] In 2013, fossil fuels supplied 67 percent of U.S. electricity, but renewables made up 38 percent of the new generation capacity (over 5 GW out of 13.5 GW).[47] From 2007 to 2014, use of lower- and zero-carbon energy sources has grown, while other major energy sources such as coal and oil have experienced declines. Renewable electricity generation, including from large hydro-electric projects, grew from 8 percent to 13 percent over that time period.[48] Between 2000 and 2013, approximately 90 percent of new power generation capacity built in the U.S. has come in the form of natural gas or renewable energy facilities.[49] In 2015, the U.S. Energy Information Administration (EIA) projected the need for 28.4 GW of additional base load or intermediate load generation capacity through 2020, with approximately 0.7 GW of new coal-fired capacity, 5.5 GW of new nuclear capacity, and 14.2 GW of new NGCC capacity already in development.[50]

The change in the resource mix has accelerated in recent years, but wind, solar, other renewables, and energy-efficiency resources have been reliably participating in the electric sector for a number of years. This rapid development of non-fossil fuel resources is occurring as much of the existing power generation fleet in the U.S. is aging and in need of modernization and replacement.[51] For example, the average age of U.S. coal steam units in 2015 is 45 years.[52] In its *2013 Report Card for America's Infrastructure,* the American Society for Civil Engineers noted that ''America relies on an aging electrical grid and pipeline distribution systems, some of which originated in the 1880s.'' [53] While there has been an increased investment in electric transmission infrastructure since 2005, the report also found that ''ongoing permitting issues, weather events, and limited maintenance have contributed to an increasing number of failures and power interruptions.''[54] However, innovative technologies have increasingly entered the electric energy space, helping to provide new answers to how to meet the electricity needs of the nation. These new technologies can enable the nation to answer not just questions as to how to reliably meet electricity demand, but also how to meet electricity demand reliably and cost-effectively[55] with the lowest possible emissions and the greatest efficiency.

Natural gas has a long history of meeting electricity demand in the U.S. with a rapidly growing role as domestic supplies of natural gas have dramatically increased. Natural gas net generation increased by approximately 36 percent between 2004 and 2014.[56] In 2014, natural gas accounted for approximately 27 percent of net generation.[57] The EIA projects that this demand growth will continue, with its *Annual Energy Outlook 2015* (AEO 2015) reference case forecasting that natural gas will produce 31 percent of U.S. electric generation in 2040.[58]

Renewable sources of electric generation also have a history of meeting electricity demand in the U.S. and are expected to have an increasing role going forward. A series of energy crises provided the impetus for renewable energy development in the early 1970s. The OPEC oil embargo in 1973 and oil crisis of 1979 caused oil price spikes, more frequent energy shortages, and significantly affected the national and global economy. In 1978, partly in response to fuel security concerns, Congress passed the Public Utilities Regulatory Policies Act (PURPA) which required local electric utilities to buy power from qualifying facilities (QFs).[59] QFs were either cogeneration facilities [60] or small

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[44] These figures are based on data for EGUs in the Acid Rain Program plus additional ones that report to the EPA under the Regional Greenhouse Gas Initiative.

[45] U.S. Energy Information Administration, ''Table 7.2b Electricity Net Generation: Electric Power Sector'' data from April 2014 Monthly Energy Review, release data April 25, 2014, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf*.

[46] U.S. Energy Information Administration, ''Table 7.2b Electricity Net Generation: Electric Power Sector'' data from April 2014 Monthly Energy Review, release data April 25, 2014, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf*.

[47] Based on Table 6.3 (New Utility Scale Generating Units by Operating Company, Plant, Month, and Year) of the U.S. Energy Information Administration (EIA) Electric Power Monthly, data for December 2013, for the following renewable energy sources: Solar, wind, hydro, geothermal, landfill gas, and biomass. Available at: *http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_03*.

[48] Bloomberg New Energy Finance and the Business Council for Sustainable Energy, *2015 Factbook: Sustainable Energy in America,* at 16 (2015), *available at http://www.bcse.org/images/2015%20Sustainable%20Energy%20in%20America%20Factbook.pdf*.

[49] Energy Information Administration, *Electricity: Form EIA–860 detailed data* (Feb. 17, 2015), *available at http://www.eia.gov/electricity/data/eia860/*.

[50] EIA, *Annual Energy Outlook for 2015 with Projections to 2040,* Final Release, *available at http://www.eia.gov/forecasts/AEO/pdf/0383(2015)*. The AEO numbers include projects that are under development and model-projected nuclear, coal, and NGCC projects.

[51] Quadrennial Energy Review, *http://energy.gov/epsa/quadrennial-energy-review-qer*.

[52] We calculated the average age of coal steam units based on the NEEDS inventory, and included units with planned retirements in 2015–2016. *See http://www.epa.gov/airmarkets/documents/ipm/needs_v514.xlsx*.

[53] American Society for Civil Engineers, *2013 Report Card for America's Infrastructure* (2013), *available at http://www.infrastructurereportcard.org/energy/*.

[54] American Society for Civil Engineers, *2013 Report Card for America's Infrastructure* (2013), *available at http://www.infrastructurereportcard.org/energy/*.

[55] Business Council for Sustainable Energy Comments in Docket Id. No. EPA–HQ–OAR–2013–0602 at 2 (Nov. 19, 2014).

[56] U.S. Energy Information Administration (EIA), *Electric Power Monthly: Table 1.1 Net Generation by Energy Source: Total (All Sectors), 2004–December 2014* (2015), *available at http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_1*.

[57] *Id.*

[58] The AEO 2015 Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, and resource assumptions. U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2015 with Projections to 2040,* at 24–25 (2015), *available at http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf*.

[59] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 220–221 (2d ed. 2010).

[60] Cogeneration facilities utilize a single source of fuel to produce both electricity and another form of energy such as heat or steam. Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 220–221 (2d ed. 2010).

generation resources that use renewables such as wind, solar, biomass, geothermal, or hydroelectric power as their primary fuels.[61] Through PURPA, Congress supported the development of more renewable energy generation in the U.S. States have taken a significant lead in requiring the development of renewable resources. In particular, a number of states have adopted renewable portfolio standards (RPS). As of 2013, 29 states and the District of Columbia have enforceable RPS or similar laws.[62] In its AEO 2015 Reference case, the EIA found that renewable energy will account for 38 percent of the overall growth in electricity generation from 2013 to 2040.[63] The AEO 2015 Reference case forecasts that the renewables share of U.S. electricity generation will grow from 13 percent in 2013 to 18 percent in 2040.[64]

Price pressures caused by oil embargoes in the 1970s also brought the issues of conservation and energy efficiency to the forefront of U.S. energy policy.[65] This trend continued in the early 1990s. Some state regulatory commissions and utilities supported energy efficiency through least-cost planning, with the National Association of Regulatory Utility Commissioners (NARUC) ''adopting a resolution that called for the utility's least cost plan to be the utility's most profitable plan.'' [66] Energy efficiency has been utilized to meet energy demand to varying levels since that time. As of April 2014, 25 states [67] have ''enacted long-term (3+ years), binding energy savings targets, or energy efficiency resource standards (EERS).'' [68] Funding for energy efficiency programs has grown rapidly in recent years, with budgets for electric efficiency programs totaling $5.9 billion in 2012.[69]

Advancements and innovation in power sector technologies provide the opportunity to address CO_2 emission levels at affected power plants while at the same time improving the overall power system in the U.S. by lowering the carbon intensity of power generation, and ensuring a reliable supply of power at a reasonable cost.

2. Fossil Fuel-Fired EGUs Regulated by this Action, Generally

Natural gas-fired EGUs typically use one of two technologies: NGCC or simple cycle combustion turbines. NGCC units first generate power from a combustion turbine (the combustion cycle). The unused heat from the combustion turbine is then routed to a heat recovery steam generator (HRSG) that generates steam, which is then used to produce power using a steam turbine (the steam cycle). Combining these generation cycles increases the overall efficiency of the system. Simple cycle combustion turbines use a single combustion turbine to produce electricity (*i.e.,* there is no heat recovery or steam cycle). The power output from these simple cycle combustion turbines can be easily ramped up and down making them ideal for ''peaking'' operations.

Coal-fired utility boilers are primarily either pulverized coal (PC) boilers or fluidized bed (FB) boilers. At a PC boiler, the coal is crushed (pulverized) into a powder in order to increase its surface area. The coal powder is then blown into a boiler and burned. In a coal-fired boiler using FB combustion, the coal is burned in a layer of heated particles suspended in flowing air.

Power can also be generated using gasification technology. An IGCC unit gasifies coal or petroleum coke to form a synthetic gas (or syngas) composed of carbon monoxide (CO) and hydrogen (H_2), which can be combusted in a combined cycle system to generate power.

3. Technological Developments and Costs

Natural gas prices have decreased dramatically and generally stabilized in recent years as new drilling techniques have brought additional supply to the marketplace and greatly increased the domestic resource base. As a result, natural gas prices are expected to be competitive for the foreseeable future, and EIA modeling and utility announcements confirm that utilities are likely to rely heavily on natural gas to meet new demand for electricity generation. On average, as discussed below, the cost of generation from a new natural-gas fired power plant (a NGCC unit) is expected to be significantly lower than the cost of generation from a new coal-fired power plant.[70]

Other drivers that may influence decisions to build new power plants are increases in renewable energy supplies, often due to state and federal energy policies. As previously discussed, many states have adopted RPS, which require a certain portion of electricity to come from renewable energy sources such as solar or wind. The federal government has also offered incentives to encourage further deployment of other forms of electric generation including renewable energy sources and new nuclear power plants.

Reflecting these factors, the EIA projections from the last several years show that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2020, along with renewable energy, nuclear power, and a limited amount of coal with CCS.[71]

While EIA data shows that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2030, a few coal-fired units still remain as viable projects at various advanced stages of construction and development. One new coal facility that has essentially completed construction,

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[61] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 220–221 (2d ed. 2010).

[62] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2014 with Projections to 2040,* at LR–5 (2014).

[63] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2015 with Projections to 2040,* at E–12 (2015).

[64] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2015 with Projections to 2040,* at 24–25(2015).

[65] Edison Electric Institute, *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities,* at 1 (2007). Congress passed legislation in the 1970s that jumpstarted energy efficiency in the U.S. For example, President Ford signed the Energy Policy and Conservation Act (EPCA) of 1975—the first law on the issue. EPCA authorized the Federal Energy Administration (FEA) to ''develop energy conservation contingency plans, established vehicle fuel economy standards, and authorized the creation of efficiency standards for major household appliances.'' Alliance to Save Energy, *History of Energy Efficiency,* at 6 (2013) (citing Anders, *''The Federal Energy Administration,''* 5; Energy Policy and Conservation Act, S. 622, 94th Cong. (1975–1976)), *available at https://www.ase.org/sites/ase.org/files/resources/Media%20browser/ee_commission_history_report_2–1–13.pdf.*

[66] Edison Electric Institute, *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities,* at 1 (2007), *available at http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/Making_Business_Energy_Efficiency.pdf.*

[67] American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards (EERS)* (2014), *available at http://aceee.org/files/pdf/policy-brief/eers-04-2014.pdf.* ACEEE did not include Indiana (EERS eliminated), Delaware (EERS pending), Florida (programs funded at levels far below what is necessary to meet targets), Utah, or Virginia (voluntary standards) in its calculation.

[68] American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards (EERS)* (2014), *available at http://aceee.org/files/pdf/policy-brief/eers-04–2014.pdf.*

[69] American Council for an Energy-Efficient Economy, *The 2013 State Energy Efficiency Scorecard,* at 17 (Nov. 2013), *available at http://aceee.org/sites/default/files/publications/researchreports/e13k.pdf.*

[70] Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015 *http://www.eia.gov/forecasts/aeo/electricity_generation.html.*

[71] *http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf; http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf; http://prod-http-80-800498448.us-east-1.elb.amazonaws.com/w/images/6/6d/0383%282011%29.pdf.*

Southern Company's Kemper County Energy Facility, deploys IGCC with partial CCS. Additionally, another project, Summit Power's Texas Clean Energy Project (TCEP), which will deploy IGCC with CCS, continues as a viable project.[72] The EIA modeling projects that coal-fired power generation will remain the single largest portion of the electricity sector beyond 2030. The EIA modeling also projects that few, if any, new coal-fired EGUs will be built in this decade and that those that are built will have CCS.[73] Continued progress on these projects is consistent with the EIA modeling that suggests that a small number of coal-fired power plants may be constructed. The primary reasons for this rate of current and projected future development of new coal projects include highly competitive natural gas prices, lower electricity demand growth, and increases in the supply of renewable energy. We recognize, however, that a variety of factors may come into play in a decision to build new power generation, and we want to ensure that there are standards in place to make sure that whatever fuel is utilized is done so in a way that minimizes CO_2 emissions, as Congress intended with CAA section 111.[74]

4. Energy Sector Modeling

Various energy sector modeling efforts, including projections from the EIA and the EPA, forecast trends in new power plant construction and utilization of existing power plants that are consistent with the above-described technological developments and costs. The EIA's annual report, the AEO, forecasts the structure of and developments in the power sector. These reports are based on economic modeling that reflects existing policy and regulations, such as state RPS programs and federal tax credits for renewables.[75] The current report, AEO 2015:[76] (i) Shows that a modest amount of coal-fired power plants that are currently under construction are expected to begin operation in the next several years (referred to as ''planned''); and (ii) projects in the reference case[77] that a very small amount of new (''unplanned'') conventional coal-fired capacity, with CCS, will come online after 2012 and through 2037 in response to federal and state incentives. According to the AEO 2015, the vast majority of new generating capacity during this period will be either natural gas-fired or renewable sources. Similarly, the EIA projections from the last several years show that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2030.[78]

Specifically, the AEO 2015 projects 30.3 GW of additional base load or intermediate load generation capacity through 2020 (this includes projects that are under development—*i.e.,* being constructed or in advance planning—and model-projected nuclear, coal, and NGCC projects). The vast majority of this new electric capacity (20.4 GW) is already under development (under construction or in advanced planning); it includes about 0.7 GW of new coal-fired capacity, 5.5 GW of new nuclear capacity, and 14.2 GW of new NGCC capacity. The EPA believes that most current fossil fuel-fired projects are already designed to meet limits consistent with this rule (or they have already commenced construction and are thus not subject to these final standards). The AEO 2015 also projects an additional 9.9 GW of new base load capacity additions, which are model-projected (unplanned). This consists of 7.7 GW of new NGCC capacity, 1.2 GW of new geothermal capacity, 0.7 GW of new hydroelectric capacity, and 0.3 GW of new coal equipped with CCS (incentivized with some government funding). Therefore, the AEO 2015 projection suggests that the new power generation capacity added through 2020 is expected to already meet the final emissions standards without incurring further control costs. This is also true during the period from 2020 through 2030, where new model-projected (unplanned) intermediate and base load capacity is expected to be compliant with the standards without incurring further control costs (*i.e.,* an additional 31.3 GW of NGCC and no additional coal, for a total, from 2015 through 2030, of 39 GW of NGCC and 0.3 GW of coal with CCS).

Under the EIA projections, existing coal-fired generation will remain an important part of the mix for power generation. Modeling from both the EIA and the EPA project that coal-fired generation will remain the largest single source of electricity in the U.S. through 2040. Specifically, in the EIA's AEO 2015, coal will supply approximately 40 percent of all electricity in the electric power sector in both 2020 and 2025.

The EPA modeling using the Integrated Planning Model (IPM), a detailed power sector model that the EPA uses to support power sector regulations, also shows limited future construction of new coal-fired power plants under the base case.[79] The EPA's projections from IPM can be found in the RIA.

5. Integrated Resource Plans

The trends in the power sector described above are also apparent in publicly available long-term resource plans, known as integrated resource plans (IRPs).

The EPA has reviewed publicly available IRPs from a range of companies (*e.g.,* varying in size, location, current fuel mix), and these plans are generally consistent with both EIA and EPA modeling projections.[80] These IRPs indicate that companies are focused on demand-side management programs to lower future electricity demand and are mostly reliant on a mix of new natural gas-fired generation and renewable energy to meet increased load demand and to replace retired generation capacity.

Notwithstanding this clear trend towards natural gas-fired generation and renewables, many of the IRPs highlight the value of fuel diversity and include options to diversify new generation capacity beyond natural gas and renewable energy. Several IRPs indicate that companies are considering new nuclear generation, including either traditional nuclear power plants or small modular reactors, and a smaller number are considering new coal-fired generation capacity with and without CCS technology. Based on public comments and on the information contained in these IRPs, the EPA acknowledges that a small number of

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[72] ''Odessa coal-to-gas power plant to break ground this year'', Houston Chronicle (April 1, 2015).

[73] This projection is for business as usual and does not account for the proposed or final CO_2 emission standard. Even in its sensitivity analysis that assumes higher natural gas prices and electricity demand, EIA does not project any additional coal-fired power plants beyond its reference case until 2023, in a case where power companies assume no GHGs emission limitations, and until 2024 in a case where power companies do assume GHGs emission limitations.

[74] These sources received federal assistance under EPAct 2005. See Section III.H.3.g below. However, none of the constraints in that Act affect the discussion in the text above, since that discussion does not relate to technology use or emissions reduction by these sources.

[75] *http://www.eia.gov/forecasts/aeo/chapter_legs_regs.cfm.*

[76] Energy Information Administration's Annual Energy Outlook for 2015, Final Release available at *http://www.eia.gov/forecasts/aeo/index.cfm.*

[77] EIA's reference case projections are the result of its baseline assumptions for economic growth, fuel supply, technology, and other key inputs.

[78] Annual Energy Outlook 2010, 2011, 2012, 2013, 2014 and 2015.

[79] *http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation.*

[80] Technical Support Document—''Review of Electric Utility Integrated Resource Plans'' (May 2015), available in the rulemaking docket EPA–HQ–OAR–2013–0495.

new coal-fired power plants may be built in the near future. While this outcome would be contrary to the economic modeling predictions, the agency understands that economic modeling may not fully reflect the range of factors that a particular company may consider when evaluating new generation options, such as fuel diversification. Further, it is possible that some of this potential new coal-fired construction may occur because developers are able to design projects with specific business plans, such as the cogeneration of chemicals, which allow the source to provide competitively priced electricity in specific geographic regions.

D. Statutory Background

The U.S. Supreme Court ruled in *Massachusetts* v. *EPA* that GHGs [81] meet the definition of ''air pollutant'' in the CAA,[82] and premised its decision in *AEP* v. *Connecticut,*[83] that the CAA displaced any federal common law right to compel reductions in CO_2 emissions from fossil fuel-fired power plants, on its view that CAA section 111 applies to GHG emissions.

CAA section 111 authorizes and directs the EPA to prescribe new source performance standards (NSPS) applicable to certain new stationary sources (including newly constructed, modified and reconstructed sources).[84] As a preliminary step to regulation, the EPA must list categories of stationary sources that the Administrator, in his or her judgment, finds ''cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' The EPA has listed and regulated more than 60 stationary source categories under CAA section 111.[85] The EPA listed the two source categories at issue here in the 1970s—listing fossil fuel-fired electric steam generating units in 1971 [86] and listing combustion turbines in 1977.[87]

Once the EPA has listed a source category, the EPA proposes and then promulgates ''standards of performance'' for ''new sources'' in the category.[88] A ''new source'' is ''any stationary source, the construction or modification of which is commenced after,'' in general, final standards applicable to that source are promulgated or, if earlier, proposed.[89] A modification is ''any physical change . . . or change in the method of operation . . . 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.'' [90] The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.[91]

The NSPS general provisions (40 CFR part 60, subpart A) provide that an existing source is considered to be a new source if it undertakes a ''reconstruction,'' which is the replacement of components of an existing facility to an extent 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.[92]

CAA section 111(a)(1) defines a ''standard of performance'' as ''a standard for emissions . . . achievable through the application of the best system of emission reduction which [considering cost, non-air quality health and environmental impact, and energy requirements] the Administrator determines has been adequately demonstrated.'' This definition makes clear that the standard of performance must be based on ''the best system of emission reduction . . . adequately demonstrated'' (BSER).

The standard that the EPA develops, reflecting the performance of the BSER, is commonly a numeric emission limit, expressed as a numeric performance level that can either be normalized to a rate of output or input (*e.g.,* tons of pollution per amount of product produced—a so-called rate-based standard), or expressed as a numeric limit on mass of pollutant that may be emitted (*e.g.,* 100 ug/m^3—parts per billion). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance.[93] Rather, sources generally may select any measure or combination of measures that will achieve the emissions level of the standard.[94] In establishing standards of performance, the EPA has significant discretion to create subcategories based on source type, class, or size.[95]

The text and legislative history of CAA section 111, as well as relevant court decisions, identify the factors that the EPA is to consider in making a BSER determination. The system of emission reduction must be technically feasible, the costs of the system must be reasonable, and the emission standard that the EPA promulgates based on the system of emission reduction must be achievable. In addition, in identifying a BSER, the EPA must consider the amount of emissions reductions attributable to the system, and must also consider non-air quality health and environmental impacts and energy requirements. The case law addressing CAA section 111 makes it clear that the EPA has discretion in weighing costs, amount of emission reductions, energy requirements, and impacts of non-air quality pollutants, and may weigh them differently for different types of sources or air pollutants. We note that under the case law of the D.C. Circuit, another factor is relevant for the BSER determination: Whether the standard would effectively promote further deployment or development of advanced technologies. Within the constraints just described, the EPA has discretion in identifying the BSER and the resulting emission standard. See generally Section III.H below.

For more than four decades, the EPA has used its authority under CAA section 111 to set cost-effective emission standards which ensure that newly constructed, reconstructed, and modified stationary sources use the best performing technologies to limit emissions of harmful air pollutants. In this final action, the EPA is following the same well-established interpretation and application of the law under CAA section 111 to address GHG emissions from newly constructed, reconstructed, and modified fossil fuel-fired power plants. For each of the standards in this final action, the EPA considered a number of alternatives and evaluated them against the statutory factors. The BSER for each category of affected EGUs and the standards of performance based on these BSER are based on that evaluation.

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[81] The EPA's 2009 endangerment finding defines the air pollution which may endanger public health and welfare as the well-mixed aggregate group of the following gases: CO_2, methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

[82] 549 U.S. 497, 520 (2007).

[83] 131 S.Ct. 2527, 2537–38 (2011).

[84] CAA section 111(b)(1)(A).

[85] *See generally* 40 CFR part 60, subparts D–MMMM.

[86] 36 FR 5931 (March 31, 1971).

[87] 42 FR 53657 (October 3, 1977).

[88] CAA section 111(b)(1)(B).

[89] CAA section 111(a)(2).

[90] CAA section 111(a)(4); See also 40 CFR 60.14 concerning what constitutes a modification, how to determine the emission rate, how to determine an emission increase, and specific actions that are not, by themselves, considered modifications.

[91] 40 CFR 60.2, 60.14(e).

[92] 40 CFR 60.15.

[93] CAA section 111(b)(5) and (h).

[94] CAA section 111(b)(5).

[95] CAA section 111(b)(2); see also *Lignite Energy Council* v. *EPA,* 198 F. 3d 930, 933 (D.C. Cir. 1999).

E. Regulatory Background

In 1971, the EPA initially included fossil fuel-fired EGUs (which includes natural gas, petroleum and coal) that use steam-generating boilers in a category that it listed under CAA section 111(b)(1)(A),[96] and promulgated the first set of standards of performance for sources in that category, which it codified in subpart D.[97] In 1977, the EPA initially included fossil fuel-fired combustion turbines in a category that the EPA listed under CAA section 111(b)(1)(A),[98] and the EPA promulgated standards of performance for that source category in 1979, which the EPA codified in subpart GG.[99]

The EPA has revised those regulations, and in some instances, has revised the codifications (that is, the 40 CFR part 60 subparts), several times over the ensuing decades. In 1979, the EPA divided subpart D into 3 subparts—Da (''Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978''), Db (''Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units'') and Dc (''Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units'')—in order to codify separate requirements that it established for these subcategories.[100] In 2006, the EPA created subpart KKKK, ''Standards of Performance for Stationary Combustion Turbines,'' which applied to certain sources previously regulated in subparts Da and GG.[101] None of these subsequent rulemakings, including the revised codifications, however, constituted a new listing under CAA section 111(b)(1)(A).

The EPA promulgated amendments to subpart Da in 2006, which included new standards of performance for criteria pollutants for EGUs, but did not include specific standards of performance for CO_2 emissions.[102] Petitioners sought judicial review of the rule, contending, among other issues, that the rule was required to include standards of performance for GHG emissions from EGUs.[103] The January 8, 2014 preamble to the proposed CO_2 standards for new EGUs [104] includes a discussion of the GHG-related litigation of the 2006 Final Rule as well as other GHG-associated litigation.

F. Development of Carbon Pollution Standards for Fossil Fuel-Fired Electric Utility Generating Units

On April 13, 2012, the EPA initially proposed standards under CAA section 111 for newly constructed fossil fuel-fired electric utility steam generating units. 77 FR 22392 (''April 2012 proposal''). The EPA withdrew that proposal (79 FR 1352 (January 8, 2014)), and, on the same day, proposed the standards addressed in this final rule. 79 FR 1430 (''January 2014 proposal''). Specifically, the EPA proposed standards under CAA section 111 to limit emissions of CO_2 from newly constructed fossil fuel-fired electric utility steam generating units and newly constructed natural gas-fired stationary combustion turbines.

In support of the January 2014 proposal, on February 26, 2014, the EPA published a notice of data availability (NODA) (79 FR 10750). Through the NODA and an associated technical support document, *Effect of EPAct05 on Best System of Emission Reduction for New Power Plants,* the EPA solicited comment on its interpretation of the provisions in the Energy Policy Act of 2005 (EPAct05),[105] including how the provisions may affect the rationale for the EPA's proposed determination that partial CCS is the best system of emission reduction adequately demonstrated for fossil fuel-fired electric utility steam generating units.

On June 18, 2014, the EPA proposed standards of performance to limit emissions of CO_2 from modified and reconstructed fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines (79 FR 34960; June 2014 proposal). Specifically, the EPA proposed standards of performance for: (1) Modified fossil fuel-fired electric utility steam generating units, (2) modified natural gas-fired stationary combustion turbines, (3) reconstructed fossil fuel-fired electric utility steam generating units, and (4) reconstructed natural gas-fired stationary combustion turbines.

G. Stakeholder Engagement and Public Comments on the Proposals

1. Stakeholder Engagement

The EPA has engaged extensively with a broad range of stakeholders and the general public regarding climate change, carbon pollution from power plants, and carbon pollution reduction opportunities. These stakeholders included industry and electric utility representatives, state and local officials, tribal officials, labor unions, non-governmental organizations and many others.

In February and March 2011, early in the process of developing carbon pollution standards for new power plants, the EPA held five listening sessions to obtain information and input from key stakeholders and the public. Each of the five sessions had a particular target audience: The electric power industry, environmental and environmental justice organizations, states and tribes, coalition groups, and the petroleum refinery industry.

The EPA conducted subsequent outreach prior to the June 2014 proposals of standards for modified and reconstructed EGUs and emission guidelines for existing EGUs, as well as during the public comment periods for the proposals. Although this stakeholder outreach was primarily framed around the GHG emission guidelines for existing EGUs, the outreach encompassed issues relevant to this rulemaking and provided an opportunity for the EPA to better understand previous state and stakeholder experience with reducing CO_2 emissions in the power sector. In addition to 11 public listening sessions, the EPA held hundreds of meetings with individual stakeholder groups, and meetings that brought together a variety of stakeholders to discuss a wide range of issues related to the electricity sector and regulation of GHGs under the CAA. The agency met with electric utility associations and electricity grid operators. Agency officials engaged with labor unions and with leaders representing large and small industries. The agency also met with energy industries, such as coal and natural gas interests, as well as with representatives of energy-intensive industries, such as

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[96] 36 FR 5931 (March 31, 1971).

[97] ''Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971,'' 36 FR 24875 (December 23, 1971) codified at 40 CFR 60.40–46.

[98] 42 FR 53657 (October 3, 1977).

[99] ''Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978,'' 44 FR 33580 (June 11, 1979).

[100] 44 FR 33580 (June 11, 1979).

[101] 71 FR 38497 (July 6, 2006), as amended at 74 FR 11861 (March 20, 2009).

[102] ''Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units, Final Rule.'' 71 FR 9866 (February 27, 2006).

[103] *State of New York, et al.* v. *EPA,* No. 06–1322.

[104] 79 FR 1430, 1444.

[105] See Section III.H.3.g below. The Energy Policy Act of 2005 (EPAct05) was signed into law by President George W. Bush on August 8, 2005. EPAct05 was intended to address energy production in the United States, including: (1) Energy efficiency; (2) renewable energy; (3) oil and gas; (4) coal; (5) Tribal energy; (6) nuclear matters and security; (7) vehicles and motor fuels, including ethanol; (8) hydrogen; (9) electricity; (10) energy tax incentives; (11) hydropower and geothermal energy; and (12) climate change technology. *www2.epa.gov/laws-regulations/summary-energy-policy-act*.

the iron and steel, and aluminum industries, to better understand the potential concerns of large industrial purchasers of electricity. In addition, the agency met with companies that offer new technology to prevent or reduce carbon pollution. The agency provided and encouraged multiple opportunities for engagement with state, local, tribal, and regional environmental and energy agencies. The EPA also met with representatives of environmental justice organizations, environmental groups, public health professionals, public health organizations, religious organizations, and other community stakeholders.

The EPA received more than 2.5 million comments submitted in response to the original April 2012 proposal for newly constructed fossil fuel-fired EGUs. Because the original proposal was withdrawn, the EPA instructed commenters that wanted their comments on the April 2012 proposal to be considered in connection with the January 2014 proposal to submit new comments to the EPA or to re-submit their previous comments. We received more comments in response to the January 2014 proposal, as discussed in the section below.

The EPA has given stakeholder input provided prior to the proposals, as well as during the public comment periods for each proposal, careful consideration during the development of this rulemaking and, as a result, it includes elements that are responsive to many stakeholder concerns and that enhance the rule. This preamble and the Response-to-Comments (RTC) document summarize and provide the agency's responses to the comments received.

2. Comments on the January 2014 Proposal For Newly Constructed Fossil Fuel-Fired EGUs

Upon publication of the January 8, 2014 proposal for newly constructed fossil fuel-fired EGUs, the EPA provided a 60-day public comment period. On March 6, 2014, in order to provide the public additional time to submit comments and supporting information, the EPA extended the comment period by 60 days, to May 9, 2014, giving stakeholders over 120 days to review, and comment upon, the January 2014 proposal, as well as the NODA. A public hearing was held on February 6, 2014, with 159 speakers presenting testimony.

The EPA received more than 2 million comments on the proposed standards for newly constructed fossil fuel-fired EGUs from a range of stakeholders that included industry and electric utility representatives, trade groups, equipment manufacturers, state and local government officials, academia, environmental organizations, and various interest groups. The agency received comments on a range of topics, including the determination that a new highly-efficient steam generating EGU implementing partial CCS was the BSER for such sources, the level of the CO_2 standard based on implementation of partial CCS, the criteria that define which newly constructed natural gas-fired stationary combustion turbines will be subject to standards, the establishment of subcategories based on combustion turbine size, and the rule's potential effects on the Prevention of Significant Deterioration (PSD) preconstruction permit program and Title V operating permit program.

3. Comments on the June 2014 Proposal For Modified and Reconstructed Fossil Fuel-Fired EGUs

Upon publication of the June 18, 2014 proposal for modified and reconstructed fossil fuel-fired EGUs, the EPA offered a 120-day public comment period—through October 16, 2014. The EPA held public hearings in four locations during the week of July 28, 2014. These hearings also addressed the EPA's June 18, 2014 proposed emission guidelines for existing fossil fuel-fired EGUs (reflecting the connections between the proposed standards for modified and reconstructed sources and the proposed emission guidelines). A total of 1,322 speakers testified, and a further 1,450 attended but did not speak. The speakers were provided the opportunity to present data, views, or arguments concerning one or both proposed actions.

The EPA received over 200 comments on the proposed standards for modified and reconstructed fossil fuel-fired EGUs from a range of stakeholders similar to those that submitted comments on the January 2014 proposal for newly constructed fossil fuel-fired EGUs (*i.e.,* industry and electric utility representatives, trade groups, equipment manufacturers, state and local government officials, academia, environmental organizations, and various interest groups). The agency received comments on a range of topics, including the methodology for determining unit-specific CO_2 standards for modified steam generating units and the use of supercritical boiler conditions as the basis for the CO_2 standards for certain reconstructed steam generating units. Many of the comments regarding modified and reconstructed natural gas-fired stationary combustion turbines are similar to the comments regarding newly constructed combustion turbines described above (*e.g.,* applicability criteria and subcategories based on turbine size).

III. Regulatory Authority, Affected EGUs and Their Standards, and Legal Requirements

In this section, we describe our authority to regulate CO_2 from fossil fuel-fired EGUs. We also describe our decision to combine the two existing categories of affected EGUs—steam generators and combustion turbines—into a single category of fossil fuel-fired EGUs for purposes of promulgating standards of performance for CO_2 emissions. We also explain that we are codifying all of the requirements in this rule for new, modified, and reconstructed affected EGUs in new subpart TTTT of part 60 of Title 40 of the Code of Federal Regulations. In addition, we explain which sources are and are not affected by this rule, and the format of these standards. Finally, we describe the legal requirements for establishing these emission standards.

A. Authority To Regulate Carbon Dioxide From Fossil Fuel-Fired EGUs

The EPA's authority for this rule is CAA section 111(b)(1). CAA section 111(b)(1)(A) requires the Administrator to establish a list of source categories to be regulated under section 111. A category of sources is to be included on the list ''if in [the Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health and welfare.'' This determination is commonly referred to as an ''endangerment finding'' and that phrase encompasses both the ''causes or contributes significantly'' component and the ''endanger public health and welfare'' component of the determination. Then, for the source categories listed under section 111(b)(1)(A), the Administrator promulgates, under section 111(b)(1)(B), ''standards of performance for new sources within such category.''

In this rule, the EPA is establishing standards under section 111(b)(1)(B) for source categories that it has previously listed and regulated for other pollutants and which now are being regulated for an additional pollutant. Because of this, there are two aspects of section 111(b)(1) that warrant particular discussion.

First, because the EPA is not listing a new source category in this rule, the EPA is not required to make a new endangerment finding with regard to affected EGUs in order to establish standards of performance for the CO_2 emissions from those sources. Under the plain language of CAA section

111(b)(1)(A), an endangerment finding is required only to list a source category. Further, though the endangerment finding is based on determinations as to the health or welfare impacts of the pollution to which the source category's pollutants contribute, and as to the significance of the amount of such contribution, the statute is clear that the endangerment finding is made with respect to the source category; section 111(b)(1)(A) does not provide that an endangerment finding is made as to specific pollutants. This contrasts with other CAA provisions that do require the EPA to make endangerment findings for each particular pollutant that the EPA regulates under those provisions. E.g., CAA sections 202(a)(1), 211(c)(1), and 231(a)(2)(A); *see also American Electric Power Co. Inc.,* v. *Connecticut,* 131 S. Ct. 2527, 2539 (2011) (''[T]he Clean Air Act directs the EPA to establish emissions standards for *categories* of stationary sources that, 'in [the Administrator's] judgment,' 'caus[e], or contribut[e] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.' § 7411(b)(1)(A).'') (emphasis added).

Second, once a source category is listed, the CAA does not specify what pollutants should be the subject of standards from that source category. The statute, in section 111(b)(1)(B), simply directs the EPA to propose and then promulgate regulations ''establishing federal standards of performance for new sources within such category.'' In the absence of specific direction or enumerated criteria in the statute concerning what pollutants from a given source category should be the subject of standards, it is appropriate for the EPA to exercise its authority to adopt a reasonable interpretation of this provision. *Chevron U.S.A. Inc.* v. *NRDC,* 467 U.S. 837, 843–44 (1984).[106]

The EPA has previously interpreted this provision as granting it the discretion to determine which pollutants should be regulated. *See* Standards of Performance for Petroleum Refineries, 73 FR 35838 (June 24, 2008) (concluding that the statute provides ''the Administrator with significant flexibility in determining which pollutants are appropriate for regulation under section 111(b)(1)(B)'' and citing cases). Further, in directing the Administrator to propose and promulgate regulations under section 111(b)(1)(B), Congress provided that the Administrator should take comment and then finalize the standards with such modifications ''as he deems appropriate.'' The D.C. Circuit has considered similar statutory phrasing from CAA section 231(a)(3) and concluded that ''[t]his delegation of authority is both explicit and extraordinarily broad.'' *National Assoc. of Clean Air Agencies* v. *EPA,* 489 F.3d 1221, 1229 (D.C. Cir. 2007).

In exercising its discretion with respect to which pollutants are appropriate for regulation under section 111(b)(1)(B), the EPA has in the past provided a rational basis for its decisions. See *National Lime Assoc.* v. *EPA,* 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (court discussed, but did not review, the EPA's reasons for not promulgating standards for oxides of nitrogen (NO_X), sulfur dioxide (SO_2) and CO from lime plants); Standards of Performance for Petroleum Refineries, 73 FR at 35859–60 (June 24, 2008) (providing reasons why the EPA was not promulgating GHG standards for petroleum refineries as part of that rule). Though these previous examples involved the EPA providing a rational basis for not setting standards for a given pollutant, a similar approach is appropriate where the EPA determines that it should set a standard for an additional pollutant for a source category that was previously listed and regulated for other pollutants.

In this rulemaking, the EPA has a rational basis for concluding that emissions of CO_2 from fossil fuel-fired power plants, which are the major U.S. source of GHG air pollution, merit regulation under CAA section 111. As noted, in 2009, the EPA made a finding that GHG air pollution may reasonably be anticipated to endanger public health or welfare, and in 2010, the EPA denied petitions to reconsider that finding. The EPA extensively reviewed the available science concerning GHG pollution and its impacts in taking those actions. In 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the finding and the denial of petitions to reconsider.[107] In addition, assessments from the NRC, the IPCC, and other organizations published after 2010 lend further credence to the validity of the Endangerment Finding. No information that commenters have presented or that the EPA has reviewed provides a basis for reaching a different conclusion. Indeed, current and evolving science discussed in detail in Section II.A of this preamble is confirming and enhancing our understanding of the near- and longer-term impacts emissions of CO_2 are having on Earth's climate and the adverse public health, welfare, and economic consequences that are occurring and are projected to occur as a result.

Moreover, the high level of GHG emissions from fossil fuel-fired EGUs makes clear that it is rational for the EPA to regulate GHG emissions from this sector. EGUs emit almost one-third of all U.S. GHGs and comprise by far the largest stationary source category of GHG emissions; indeed, as noted above, the CO_2 emissions from fossil fuel-fired EGUs are almost three times as much as the emissions from the next ten source categories combined. Further, the CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year. See, *e.g.,* Section V.K below (noting that even the difference in CO_2 emissions between a highly efficient SCPC and the same unit meeting today's standard of performance can amount to hundreds of thousands of tons each year). These facts provide a rational basis for regulating CO_2 emissions from affected EGUs.

Some commenters have argued that the EPA is required to make a new endangerment finding before it may regulate CO_2 from EGUs. We disagree, for the reasons discussed above. Moreover, as discussed in the January 2014 proposal,[108] even if CAA section 111 required the EPA to make endangerment and cause-or-contribute significantly findings as prerequisites for this rulemaking, then, so far as the ''CO_2 endangers public health and welfare'' component of an endangerment finding is concerned, the information and conclusions described above should be considered to constitute the requisite endangerment finding. Similarly, so far as a cause-or-contribute significantly finding is concerned, the information and conclusions described above should be considered to constitute the requisite finding. The EPA's rational basis for regulating CO_2 under CAA section 111 is based primarily on the analysis and conclusions in the EPA's 2009 Endangerment Finding and 2010 denial of petitions to reconsider that Finding, coupled with the subsequent assessments from the IPCC and NRC that describe scientific developments since those EPA actions. In addition, we have reviewed comments presenting other scientific information to

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[106] In *Chevron,* the U.S. Supreme Court held that an agency must, at Step 1, determine whether Congress's intent as to the specific matter at issue is clear, and, if so, the agency must give effect to that intent. If Congressional intent is not clear, then, at Step 2, the agency has discretion to fashion an interpretation that is a reasonable construction of the statute.

[107] *Coalition for Responsible Regulation* v. *EPA,* 684 F.3d 102, 119–126 (D.C. Circuit 2012).

[108] 79 FR 1430, 1455–56 (January 8, 2014).

determine whether that information has any meaningful impact on our analysis and conclusions. For both the endangerment finding and the rational basis, the EPA focused on public health and welfare impacts within the United States, as it did in the 2009 Finding. The impacts in other world regions strengthen the case because impacts in other world regions can in turn adversely affect the United States or its citizens.

More specifically, our approach here—reflected in the information and conclusions described above—is substantially similar to that reflected in the 2009 Endangerment Finding and the 2010 denial of petitions to reconsider. The D.C. Circuit upheld that approach in *Coalition for Responsible Regulation* v. *EPA,* 684 F.3d 102, 117–123 (D.C. Cir. 2012) (noting, among other things, the ''substantial . . . body of scientific evidence marshaled by EPA in support of the Endangerment Finding'' (id. at 120); the ''substantial record evidence that anthropogenic emissions of greenhouse gases 'very likely' caused warming of the climate over the last several decades'' (id. at 121); ''substantial scientific evidence . . . that anthropogenically induced climate change threatens both public health and public welfare . . . [through] extreme weather events, changes in air quality, increases in food- and water-borne pathogens, and increases in temperatures'' (id.); and ''substantial evidence . . . that the warming resulting from the greenhouse gas emissions could be expected to create risks to water resources and in general to coastal areas. . . .'' (id.)). The facts, unfortunately, have only grown stronger and the potential adverse consequences to public health and the environment more dire in the interim. Accordingly, that approach would support an endangerment finding for this rulemaking.[109]

Likewise, if the EPA were required to make a cause-or-contribute-significantly finding for CO_2 emissions from the fossil fuel-fired EGUs as a prerequisite to regulating such emissions under CAA section 111, the same facts that support our rational basis determination would support such a finding. As shown in Tables 3 and 4 in this preamble, fossil fuel-fired EGUs are very large emitters of CO_2. All told, these fossil fuel-fired EGUs emit almost one-third of all U.S. GHG emissions, and are responsible for almost three times as much as the emissions from the next ten stationary source categories combined. The CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year, and the CO_2 emissions from even a single NGCC unit may amount to one million or more tons per year. It is not necessary in this rulemaking for the EPA to decide whether it must identify a specific threshold for the amount of emissions from a source category that constitutes a significant contribution; under any reasonable threshold or definition, the emissions from combustion turbines and steam generators are a significant contribution. Indeed, these emissions far exceed in magnitude the emissions from motor vehicles, which have already been held to contribute to the endangerment. See *Coalition for Responsible Regulation,* 684 F. 3d at 121 (''substantial evidence'' supports the EPA's determination ''that motor-vehicle emissions of greenhouse gases contribute to climate change and thus to the endangerment of public health and welfare'').[110]

B. Treatment of Categories and Codification in the Code of Federal Regulations

As discussed in the January 2014 proposal of carbon pollution standards for newly constructed EGUs (79 FR 1430) and above, in 1971 the EPA listed fossil fuel-fired steam generating boilers as a new category subject to CAA section 111 rulemaking, and in 1979 the EPA listed fossil fuel-fired combustion turbines as a new category subject to the CAA section 111 rulemaking. In the ensuing years, the EPA has promulgated standards of performance for the two categories and codified those standards, at various times, in 40 CFR part 60, subparts D, Da, GG, and KKKK.

In the January 2014 proposal of carbon pollution standards for newly constructed EGUs (79 FR 1430) and the June 2014 proposal of carbon pollution standards for modified and reconstructed EGUs (79 FR 34960), the EPA proposed separate standards of performance for new, modified, and reconstructed sources in the two categories. The EPA took comment on combining the two categories into a single category solely for purposes of the CO_2 emissions from new, modified, and reconstructed affected EGUs. In addition, the EPA proposed codifying the standards of performance in the same Da and KKKK subparts that currently contain the standards of performance for other pollutants from those sources addressed in the NSPS program, but co-proposed codifying all the standards of performance for CO_2 emissions in a new 40 CFR part 60, subpart TTTT.

In this rule, the EPA is combining the steam generator and combustion turbine categories into a single category of fossil fuel-fired electricity generating units for purposes of promulgating standards of performance for GHG emissions. Combining the two categories is reasonable because they both provide the same product: Electricity services. Moreover, combining them in this rule is consistent with our decision to combine them in the CAA section 111(d) rule for existing sources that accompanies this rule. In addition,

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[109] Nor does the EPA consider the cost of potential standards of performance in making this Finding. Like the Endangerment Finding under section 202(a) at issue in *State of Massachusetts* v. *EPA,* 549 U.S. 497 (2007) the pertinent issue is a scientific inquiry as to whether an endangerment to public health or welfare from the relevant air pollution may reasonably be anticipated. Where, as here, the scientific inquiry conducted by the EPA indicates that these statutory criteria are met, the Administrator does not have discretion to decline to make a positive endangerment finding to serve other policy grounds. Id. at 532–35. In this regard, an endangerment finding is analogous to setting national ambient air quality standards under section 109(b), which similarly call on the Administrator to set standards that in her ''judgment'' are ''requisite to protect the public health''. The EPA is not permitted to consider potential costs of implementation in setting these standards. *Whitman* v. *American Trucking Assn's,* 531 U.S. 457, 466 (2001); see also *Michigan* v. *EPA,* U.S. (no. 14–46, June 29, 2015) slip op. pp. 10–11 (reiterating *Whitman* holding). The EPA notes further that section 111(b)(1) contains no terms such as ''necessary and appropriate'' which could suggest (or, in some contexts, require) that costs may be considered as part of the finding. Compare CAA section 111(n)(1)(A); see *State of Michigan,* slip op. pp. 7–8. The EPA, of course, must consider costs in determining whether a best system of emission reduction is adequately demonstrated and so can form the basis for a section 111(b) standard of performance, and the EPA has carefully considered costs here and found them to be reasonable. See section V. H. and I. below. The EPA also has found that the rule's quantifiable benefits exceed regulatory costs under a range of assumptions were new capacity to be built. RIA chapter 5 and section XIII.G below. Accordingly, this endangerment finding would be justified if (against our view) it is both required, and (again, against our view) costs are to be considered as part of the finding.

[110] The ''air pollution'' defined in the Endangerment Finding is the atmospheric mix of six long-lived and directly emitted greenhouse gases: Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). See 74 FR 66496 at 66497. The standards of performance adopted in the present rulemaking address only one component of this air pollution: CO_2. This is reasonable, given that CO_2 is the air pollutant emitted in the largest volume by the source category, and which is (necessarily) emitted by every affected EGU. There is, of course, no requirement that standards of performance address each component of the air pollution which endangers. Section 111(b)(1)(A) requires the EPA to establish ''standards of performance'' for listed source categories, and the definition of ''standard of performance'' in section 111(a)(1) does not specify which air pollutants must be controlled. See also Section III.G below explaining that CH_4 and N_2O emissions represent less than 1 percent of total estimated GHG emissions (as CO_2e) from fossil fuel-fired electric power generating units.

many of the monitoring, reporting, and verification requirements are the same for both source categories, and, as discussed next, we are codifying all requirements in a single new subpart of the regulations; as a result, combining the two categories into a single category will reduce confusion. It should be noted that in this rule, we are not combining the two categories for purposes of standards of performance for other air pollutants.

Because these two source categories are pre-existing listed source categories and the EPA will not be subjecting any additional sources in the categories to CAA regulation for the first time, the combination of these two categories is not considered a new source category subject to the listing requirements of CAA section 111(b)(1)(A). As a result, this final rule does not list a new category under CAA section 111(a)(1)(A), nor does this final rule revise either of the two source categories. Thus, the EPA is not required to make a new endangerment and contribution finding for the combination of the two categories,[111] although as discussed in the previous section, the evidence strongly supports such findings. Thus, the EPA has found, in the alternative, that this category of sources contributes significantly to air pollution which may be reasonably anticipated to endanger public health and welfare.

C. Affected Units

We generally refer to fossil fuel-fired electric generating units that would be subject to a CAA section 111 emission standard as ''affected'' or ''covered'' sources, units, facilities or simply as EGUs. An EGU is any boiler, IGCC unit, or combustion turbine (in either simple cycle or combined cycle configuration) that meets the applicability criteria. Affected EGUs include those that commenced construction after January 8, 2014, and meet the specified applicability criteria and, for modifications and reconstructions, EGUs that commenced those activities after June 18, 2014, and meet the specified applicability criteria.

To be considered an EGU, the unit must: (1) Be capable of combusting more than 250 MMBtu/h (260 GJ/h) heat input of fossil fuel;[112] and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (*i.e.,* for sale to the grid).[113] However, we are not finalizing CO_2 standards for certain EGUs. The EGUs that are not covered by the standards we are finalizing in this rule include: (1) Non-fossil fuel units subject to a federally enforceable permit that limits the use of fossil fuels to 10 percent or less of their heat input capacity on an annual basis; (2) combined heat and power (CHP) units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than the unit's design efficiency multiplied by its potential electric output, or 219,000 MWh or less, whichever is greater; (3) stationary combustion turbines that are not physically capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline); (4) utility boilers and IGCC units that have always been subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less; (5) municipal waste combustors that are subject to subpart Eb of this part; and (6) commercial or industrial solid waste incineration units subject to subpart CCCC of this part.

D. Units Not Covered by This Final Rule

As described in the previous section, the EPA is not issuing standards of performance for certain types of sources—specifically, dedicated non-fossil fuel-fired (*e.g.,* biomass) units and industrial CHP units, as well as certain projects under development. This section discusses these sources and our rationale for not issuing standards for them. Because the rationale applies to both steam generating units and combustion turbines, we are describing it here rather than in the separate steam generating unit and combustion turbine discussions. We discuss the proposed applicability criteria, the topics where the agency solicited comment, a brief summary of the relevant comments, and the rationale for the final applicability approach for these sources.

1. Dedicated Non-fossil Fuel Units

The proposed applicability for newly constructed EGUs included those that primarily combust fossil fuels (*e.g.,* coal, oil, and natural gas). The proposed applicability criteria were that affected units must burn fossil fuels for more than 10 percent of the unit's total heat input, on average, over a 3-year period.[114] Under the proposed approach, applicability under the final NSPS for CO_2 emissions could have changed on an annual basis depending on the composition of fuel burned. We solicited comment on several aspects of the proposed applicability criteria for non-fossil fuel units. Specifically, we solicited comment on a broad applicability approach that would include non-fossil fuel-fired units as affected units, but that would impose an alternate standard when the unit fires fossil fuels for 10 percent or less of the heat input during the 3-year applicability-determination period. We solicited comment on whether, if such a subcategory is warranted, the applicability-determination period for the subcategory should be 1-year or a 3-year rolling period. We also solicited comment on whether the standard for such a subcategory should be an alternate numerical limit or ''no emission standard.''

While the proposed exemption applied to all non-fossil fuels, most commenters focused on biomass-specific issues. Many commenters supported an exclusion for biomass-fired units that fire no more than 10 percent fossil fuels. Some commenters suggested that the exclusion for biomass-fired units should be raised to a 25 percent fossil fuel-use threshold.

Many commenters supported the proposed 3-year averaging period for the fossil fuel-use criterion because it provides greater flexibility for operators to use fossil fuels when supply chains for the primary non-fossil fuels are disrupted, during unexpected malfunctions of the primary non-fossil fuel handling systems, or when the unit's maximum generating capacity is required by system operators for reliability reasons. Many commenters supported the 3-year averaging period because it is consistent with the final requirements under the EPA's Mercury and Air Toxics Standards (MATS) and would allow non-fossil fuel-fired units to use some fossil fuels for flame stabilization without triggering applicability. Some commenters requested that the EPA clarify the method an operator should use during the first 3 years of operations to determine if a particular unit will meet the 10 percent fossil fuel-use threshold. Others asked whether or not an affected facility has a compliance obligation during the first 3-year period and, if an

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[111] See, *e.g., American Trucking Assn's* v. *EPA,* 175 F.3d 1027, 1055, rev'd on other grounds sub. nom. *Whitman* v. *Am. Trucking Assn's,* 531.U.S. 457 (because fine particulate matter ($PM_{2.5}$) was already included as a sub-set of the listed pollutant particulate matter, it was not a new pollutant necessitating a new listing).

[112] We refer to the capability to combust 250 MMBtu/h of fossil fuel as the ''base load rating criterion.'' Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

[113] We refer to the capability to supply 25 MW net to the grid as the ''total electric sales criterion.''

[114] We refer to the fraction of heat input derived from fossil fuels as the ''fossil fuel-use criterion.''

affected facility does not meet the 10 percent fossil fuel-use threshold during several 12-month periods during the first 3 years, whether compliance calculations would be required for such 12-month periods. Other commenters had concerns with the 3-year averaging period, stating that a source would no longer be subject to the NSPS if it fell below the threshold for any of the applicability metrics that the EPA proposed to calculate on a 3-year (or, in some cases, annual) basis. They argued that this would create a situation in which no one would know whether a particular plant will be subject to the standards until years after the emissions had already occurred. Some commenters were concerned that plants operating near the threshold could move in and out of the regulatory system, which would provide complications for compliance, enforcement, and permitting.

After considering these comments, the EPA has concluded that the proposed fossil fuel-use criterion based on the actual amount of fossil fuel burned is not an ideal approach to determine applicability. As commenters pointed out, facilities, permitting authorities, and the public would not know when construction is commenced whether a facility will be subject to the final NSPS, and after operation has commenced, a unit could move in and out of applicability each year. The intent of this rulemaking is to establish CO_2 standards for fossil fuel-fired EGUs, not for non-fossil fuel-fired EGUs. Therefore, to simplify compliance and establish CO_2 standards for only those sources which we set out to regulate, we are finalizing a fossil fuel-use criterion that will exempt dedicated non-fossil units. Specifically, units that are capable of burning 50 percent or more non-fossil fuel are exempt from the final standards so long as they are subject to a federally enforceable permit that limits their use of fossil fuels to 10 percent or less of their heat input capacity on an annual basis. This approach establishes clear applicability criteria and avoids the prospect of units moving in and out of applicability based on their actual fuel use in a given year. Consistent with the applicability approach in the steam generating unit criteria pollutant NSPS, subpart Da, the final fossil fuel-use criterion does not include ''constructed for the purpose of'' language. Therefore, an owner or operator could change a unit's applicability in the future by seeking a modification of the unit's permit conditions. A unit with the appropriate permit limitation will not be subject to the requirements in this rulemaking. Similarly, an existing unit that takes a permit limitation restricting fossil-fuel use would no longer be an affected unit for the purposes of 111(d) state plans. This is consistent with our intent to reduce GHG emissions from fossil fuel-fired EGUs.

We considered using either an annual or 3-year average for calculating compliance with the final fossil fuel-use criterion. Ultimately, we concluded that an annual average would provide sufficient flexibility for dedicated non-fossil units to combust fossil fuels for flame stabilization and other ancillary purposes, while maintaining consistency with the 12-month compliance periods used for most permit limitations. A 3-year average potentially would allow units to combust a significant quantity of fuels in a given year, leading to higher CO_2 emissions, so long as they curtailed fossil-fuel use in a later year. This would defeat the purpose of the criterion, which is to exempt dedicated non-fossil units only. Finally, we are finalizing the 10 percent fossil-fuel use threshold in relation to a unit's heat input capacity rather than its actual heat input, which is consistent with past approaches we have taken under the industrial boiler criteria pollutant NSPS.

2. Industrial CHP Units

Another approach to generating electricity is the use of CHP units. A CHP unit can use a boiler, combustion turbine, reciprocating engine, or various other generating technologies to generate electricity and useful thermal energy in a single, integrated system. CHP units are generally more efficient than conventional power plants because the heat that is normally wasted in a conventional power generation cooling system (*e.g.,* cooling towers) is instead recovered as useful thermal output. While the EPA did propose some applicability provisions specific to CHP units (*e.g.,* subtract purchased power of adjacent facilities when determining total electric sales), in general, the proposed applicability criteria for electric-only units and CHP units were similar. The intent of the proposed total and percentage electric sales criteria was to cover only utility CHP units, not industrial CHP units. To the extent that the proposal's applicability provisions would have the effect of covering industrial CHP units, we solicited comment on an appropriate applicability exemption, and the criteria for that exemption, for highly efficient CHP facilities.

Many commenters supported the exclusion of CHP units as a means of encouraging capital investments in highly efficient and reliable distributed generation technologies. These commenters recommended that the EPA adopt an explicit exemption for CHP units at facilities that are classified as industrial (*e.g.,* gas-fired CHPs within SIC codes 2911—petroleum refining, 13—oil and gas extraction, and other industrial SIC codes as appropriate). They also stated that the EPA should exclude CHP units that have an energy savings of 10 percent or more compared to separate heat and power. One commenter suggested that the final rule should cover only industrial-commercial-institutional CHP units that supply, on a net basis, more than two-thirds of their potential combined thermal and electric energy output and more than 450,000 MWh net-electric output to a utility power distribution system on an annual basis for five consecutive calendar years. The commenter also suggested that CHP units which have total thermal energy production that approaches or exceeds their total electricity production should be exempted.

Other commenters suggested exempting CHP units by fuel type or based on the definition of potential electric output. For example, some commenters suggested modifying the percentage electric sales threshold to be based on net system efficiency (including useful thermal output) rather than the rated net-electric-output efficiency. They also suggested that the applicability criteria should use a default efficiency of 50 percent for CHP units. Some commenters suggested that a CHP unit should not be considered an affected EGU if 20 percent or more of its total gross or net energy output consisted of useful thermal output on a 3-year rolling average basis. Other commenters said that highly efficient CHP units that achieve an overall efficiency level of 60 to 70 percent or higher should be excluded from applicability.

The intent of this rulemaking is to cover only utility CHP units, because they serve essentially the same purpose as electric-only EGUs (*i.e.,* the sale of electricity to the grid). Industrial CHP units, on the other hand, serve a different primary purpose (*i.e.,* providing useful thermal output with electric sales as a by-product). With these facts in mind and after considering the comments, the EPA has concluded that it is appropriate to consider two factors for the final CHP exemption: (1) Whether the primary purpose of the CHP unit is to provide useful thermal output rather than electricity and (2) whether the CHP unit is highly efficient and thus achieves environmental benefits.

We rejected many of the approaches suggested by the commenters because they did not achieve one or both of the factors we identified. Specifically, the EPA has concluded that SIC code classification is not a sufficient indicator of the purpose (*i.e.,* it does not correlate to useful thermal output) or environmental benefits (*i.e.,* efficiency) of a unit. Further, an exemption based on SIC code could result in circumvention of the intended applicability. For example, this approach would allow a new EGU to locate near an industrial site, provide a trivial amount of useful thermal output to that site, sell electricity to the grid, and nonetheless avoid applicability. Similarly, increasing the electric sales criteria to two-thirds of potential electric output and 450,000 MWh would essentially amount to a blanket exemption that tells us nothing about the primary purpose or efficiency of the unit.

On the other hand, exemptions based on useful thermal output being greater than 20 percent of total output, thermal output being greater than electric output, or overall design efficiency value would identify whether the primary purpose of a unit is to generate thermal output, but they would not recognize the environmental benefits of highly efficient CHP units. While overall efficiency may appear to be a good indicator of environmental benefits, this is not always the case with CHP units. Overall efficiency is a function of both efficient design and the power to heat ratio (the amount of electricity relative to the amount of useful thermal output). For example, boiler-based CHP units tend to produce large amounts of useful thermal output relative to electric output and tend to have high overall efficiencies. For units producing primarily useful thermal output, the equivalent separate heat and power efficiency (*i.e.,* the theoretical overall efficiency if the electricity and useful thermal output were produced by a stand-alone EGU and stand-alone boiler) would approach that of a stand-alone boiler (*e.g.,* 80 percent). However, combustion turbine-based CHP units tend to produce relatively equal amounts of electricity and useful thermal output. In this case, the equivalent separate heat and power efficiency would be closer to 65 percent. Therefore, an exemption based on overall efficiency is not an indication of the fuel savings a CHP unit will achieve relative to separate heat and power. Further, this approach would encourage the development of CHP units that just meet the efficiency exemption criterion and would still cover many combustion turbine-based industrial CHP units. Conversely, while an exemption based on fuel savings relative to separate heat and power would recognize the environmental benefit of highly efficient CHP units, it would not consider the primary purpose of the CHP unit.

In the end, the EPA has concluded that maintaining the proposed percentage electric sales criterion with two adjustments addresses both factors with which we are concerned. First, we are changing the definition of ''potential electric output'' to be based on overall net efficiency at the maximum electric production rate, instead of just electric-only efficiency. Second, we are changing the percentage electric sales criterion to reflect the sliding scale, which is the overall design efficiency, calculated at the maximum useful thermal rating of the CHP unit (*e.g.,* a CHP unit with a extraction condensing steam turbine would determine the efficiency at the maximum extraction/bypass rate), of the unit multiplied by the unit's potential electric output instead of one-third of potential electric output as proposed. This approach recognizes the primary purpose of industrial CHP units by providing a more generous percentage electric sales exemption to CHP units with high thermal output. As described previously, CHP units with high thermal loads tend to be more efficient and will therefore have a higher allowable percentage electric sales. By amending both the definition of ''potential electric output'' and the electric sales threshold, we assure that CHP units that primarily produce useful thermal output are exempted as industrial CHP units even if they are selling all of their electric output to the grid. As the relative amount of electricity generated by the CHP unit increases, efficiency will generally decrease, thus limiting allowable electric sales before applicability is triggered. This approach also recognizes the environmental benefits of increased efficiency by encouraging industrial CHP units to be designed as efficiently as possible to take advantage of the higher electric sales permitted by the sliding scale.

In conclusion, a CHP unit will be an affected source unless it is subject to a federally enforceable permit that limits annual total electric sales to less than or equal to the unit's design efficiency multiplied by its potential electric output or 219,000 MWh,[115] whichever is greater. This final applicability criterion will only cover CHP units that condense a significant portion of steam generated by the unit and use the electric power generated as a result of condensing that steam to supply electric power to the grid. CHP facilities that do not have a condensing steam turbine (*e.g.,* combustion turbine-based CHP units without a steam turbine and boiler-based systems with a backpressure steam turbine) would generally not be physically capable of selling enough electricity to meet the applicability criterion, even if they sold 100 percent of the electricity generated and did not subtract out the electricity used by the thermal host(s). The EPA has concluded that this is appropriate because these sources are industrial by design and provide mostly useful thermal output.

CHP facilities with a steam extraction condensing steam turbine will determine their potential electric output based on their efficiency on a net basis at the maximum electric production rate at the base load heat input rating (*e.g.,* the CHP is condensing as much steam as possible to create electricity instead of using it for useful thermal output). We have concluded that it is necessary for CHP units with extraction condensing steam turbines to calculate their potential electric output at the maximum condensing level to avoid circumvention of the applicability criteria. For example, to avoid applicability a CHP unit could locate next to an industrial host and have the capability of selling significant quantities of useful thermal output without ever actually intending to supply much, if any, useful thermal output to the industrial host. If we calculated the potential electric output at the maximum level of thermal output, this type of CHP unit could operate at full condensing mode at base load conditions for the entire year and still not exceed the electric sales threshold. During the permitting process, the owner or operator will be able to determine if the unit is subject to the final standards in this rule.

New EGUs with only limited useful thermal output will be subject to the final standards, but the vast majority of new CHP units will be classified as industrial CHP and will not be subject to the final standards. The EPA has concluded that this approach is similar to exempting CHP facilities that sell less than half of their total output (electricity plus thermal), but has the benefit of accounting for overall design efficiency.

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[115] The EPA has concluded that it is appropriate to maintain the 219,000 MWh total electric sales criterion for combustion turbine based CHP units to avoid potentially covering smaller industrial CHP units.

This approach both limits applicability to the industrial CHP units and encourages the installation of the most efficient CHP systems because more efficient designs will be able to have higher permitted electric sales while not being subject to the CO_2 standards included in this rulemaking.

3. Municipal Waste Combustors and Commercial and Industrial Solid Waste Incinerators

The purpose of this rulemaking is to establish CO_2 standards for fossil fuel-fired EGUs. Municipal waste combustors and commercial and industrial solid waste incinerators typically have not been included in this source category. Therefore, even if one of these types of units meets the general heat input and electric sales criteria, we are not finalizing CO_2 emission standards for municipal waste combustors subject to subpart Eb of this part and commercial and industrial solid waste incinerators subject to subpart CCCC of this part.

4. Certain Projects Under Development

The EPA proposed that a limited class of projects under development should not be subject to the proposed standards. These were planned sources that may be capable of commencing construction (within the meaning of section 111(a)) shortly after the standard's proposal date, and so would be classified as new sources, but which have a design which would be incapable of meeting the proposed standard of performance. See 79 FR 1461 and CAA section 111(a)(2). The EPA proposed that these sources would not be subject to the generally-applicable standard of performance, but rather would be subject to a unit-specific permitting determination if and when construction actually commences. The EPA indicated that there could be three sources to which this approach could apply, and further indicated that the EPA could ultimately adopt the generally-applicable standard of performance for these sources (if actually constructed). 79 FR 1461.

As explained at Section III.J below, the EPA is finalizing this approach in this final rule. We again note that these sources, if and when constructed, could be ultimately subject to the 1,400 lb CO_2/MWh-g standard, especially if there is no engineering basis, or demonstrated action in reliance, showing that the new source could not meet that standard.

E. Coal Refuse

In the April 2012 proposal, we solicited comment on subcategorizing and exempting EGUs that burn over 75 percent coal refuse on an annual basis. Multiple commenters supported the exemption, citing numerous environmental benefits of remediating coal refuse piles. Observing that coal refuse-fired EGUs typically use fluidized bed technologies, other commenters disagreed with any exemption, specifically citing the N_2O emissions from fluidized bed boilers. In light of the environmental benefits of remediating coal refuse piles cited by commenters, the limited amount of coal refuse, and the fact that a new coal refuse-fired EGU would be located in close proximity to the coal refuse pile, we sought additional comments regarding a subcategory for coal refuse-fired EGUs in the January 2014 proposal. Specifically, we requested additional information on the net environmental benefits of coal refuse-fired EGUs and information to support an appropriate emissions standard for coal refuse-fired EGUs. One commenter on the April 2012 proposal stated that existing coal refuse piles are naturally combusting at a rate of 0.3 percent annually, and we requested comment on this rate and the proper approach to account for naturally occurring emissions from coal refuse piles in the January 2014 proposal.

Commenters said that a performance standard is not feasible for coal refuse CFBs since there is no economically feasible way to capture CO_2 through a conveyance designed and constructed to capture CO_2. Commenters suggested that the EPA establish BSER for GHGs at modified coal refuse CFBs as a boiler tune-up that must be performed at least every 24 months. Commenters stated that the EPA should exempt coal refuse CFB units relative to their CO_2 emissions to the extent that these units offset the uncontrolled ground level emissions from spontaneous combustion of legacy coal refuse stockpiles and noted that the mining of coal waste not only produces less emissions in the long term, but also helps to reclaim land that is currently used to store coal waste. In contrast, one commenter saw no legitimate basis for coal refuse to be subcategorized and stated that it should be treated in the same manner as all other coal-fired EGUs.

The EPA has concluded that an explicit exemption or subcategory specifically for coal refuse-fired EGUs is not appropriate. The costs faced by coal refuse facilities to install CCS are similar to coal-fired EGUs burning any of the primary coals, and the final applicable requirements and standards in the rule do not preclude the development of new coal refuse-fired units without CCS. Specifically, we are not finalizing CO_2 standards for industrial CHP units. Many existing coal refuse-fired units are relatively small and designed as CHP units. Due to the expense of transporting coal refuse long distances, we anticipate that any new coal refuse-fired EGU would be relatively small in size. Moreover, sites with sufficient thermal demand exist such that the unit could be designed as an industrial CHP facility and the requirements of this rule would not apply.

F. Format of the Output-Based Standard

1. Net and Gross Output-Based Standards

For all newly constructed units, the EPA proposed standards as gross output emission rates consistent with current monitoring and reporting requirements under 40 CFR part 75.[116] For a non-CHP EGU, gross output is the electricity generation measured at the generator terminals. However, we solicited comment on finalizing equivalent net-output-based standards either as a compliance alternative or in lieu of the proposed gross-output-based standards. Net output is the gross electrical output less the unit's total parasitic (*i.e.,* auxiliary) power requirements. A parasitic load for an EGU is a load or device powered by electricity, steam, hot water, or directly by the gross output of the EGU that does not contribute electrical, mechanical, or useful thermal output. In general, parasitic energy demands include less than 7.5 percent of non-IGCC and non-CCS coal-fired station power output, approximately 15 percent of non-CCS IGCC-based coal-fired station power output, and about 2.5 percent of non-CCS NGCC power output. The use of CCS increases both the electric and steam parasitic loads used internal to the unit, and these outputs are not considered when determining the emission rate. Net output is used to recognize the environmental benefits of: (1) EGU designs and control equipment that use less auxiliary power; (2) fuels that require less emissions control equipment; and (3) higher efficiency motors, pumps, and fans. For modified and reconstructed combustion turbines, the EPA also proposed standards as gross output emission rates, but solicited comment on finalizing net output standards. The rationale was that due to the low auxiliary loads in non-CCS NGCC designs, the difference between a gross-output standard and a net-output standard has a limited

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[116] 79 FR 1447–48.

impact on environmental performance. Auxiliary loads are more significant for modified and reconstructed boilers and IGCC units, and the EPA proposed standards on a net output basis for these units. The rationale included that this would enable owners/operators of these types of units to pursue projects that reduce auxiliary loads for compliance purposes. However, the EPA solicited comment on finalizing the standards on a gross-output basis. We also proposed to use either gross-output or net-output bases for each respective subcategory of EGUs (*i.e.,* utility boilers, IGCC units, and combustion turbines) consistently across all CAA section 111(b) standards for new, modified, and reconstructed EGUs.

Many commenters supported gross-output-based standards, maintaining that a net-output standard penalizes the operation of air pollution control equipment. Several commenters disagreed with the agency's proposed rationale that a net-output standard would provide incentive to minimize auxiliary loads. The commenters believe utility commissions and existing economic forces already provide utilities with appropriate incentives to properly manage all of these factors. Some commenters supported a gross-output-based standard because variations in site conditions (*e.g.,* available natural gas pressure, available cooling water sources, and elevation) will likely penalize some owners and benefit others simply through variations in their particular plant-site conditions if a net basis is used. Several commenters stated that if the final rule includes a net-output-based standard, it should be included as an option in conjunction with a gross-output-based option.

Several commenters opposed net-output-based standards because they believe it is difficult to accurately determine the net output of an EGU. They pointed out that many facilities have transformers that support multiple units at the facility, making unit-level reporting difficult. These commenters also stated that station electric services may come from outside sources to supply certain ancillary loads. One commenter stated that the benefit of switching to net-output-based standards would be small and would not justify the substantial complexities in both defining and implementing such a standard. Conversely, other commenters stated that net-metering is a well-established technology that should be required, particularly for newly constructed units.

Other commenters, however, maintained that the final rule should strictly require compliance on a net output-basis. They believe that this is the only way for the standards to minimize the carbon footprint of the electricity delivered to consumers. These commenters believe that, at a minimum, net-output-based standards should be included as an option in the final rule.

We are only finalizing gross-output-based standards for utility boilers and IGCC units. Providing an alternate net-output-based standard that is based on gross-output-based emissions data and an assumed auxiliary load is most appropriate when the auxiliary load can be reasonably estimated and the choice between the net- and gross-output-based standard will not impact the identified BSER. For example, the auxiliary load for combustion turbines is relatively fixed and small, approximately 2.5 percent, so the choice between a gross and net-output-based standard will not substantially impact technology choices. However, in the case of utility boilers, we have concluded that we do not have sufficient information to establish an appropriate net-output-based standard that would not impact the identified BSER for these types of units. The BSER for newly constructed steam generating units is based on the use of partial CCS. However, unlike the case for combustion turbines, owners/operators of utility boilers have multiple technology pathways available to comply with the actual emission standard. The choice of both control technologies and fuel impact the overall auxiliary load. For example, a coal-fired hybrid EGU (*e.g.,* one that includes integrated solar thermal equipment for feedwater heating or steam augmentation) or a coal-fired EGU co-firing natural gas would have lower non-CCS related auxiliary loads and, because the amount of CCS needed to comply with the standard would also be smaller, the CCS auxiliary loads would also be reduced. Therefore, we cannot identify an appropriate assumed auxiliary load to establish an equivalent net-output-based standard. In addition, many IGCC facilities (which could be used as an alternative technology for complying with the standard of performance; see Sections IV.B and V.P below) have been proposed or are envisioned as co-production facilities (*i.e.,* to produce useful by-products and chemicals along with electricity). As noted in the proposal, we have concluded that predicting the net electricity at these co-production facilities would be more challenging to implement under these circumstances.

In contrast, based on further evaluation and review of issues raised by commenters, the EPA is finalizing the CO_2 standard for combustion turbine EGUs in a format that is similar to the current NSPS format for criteria pollutants. The default final standards establish a gross-output-based standard. This allows owners/operators of new combustion turbines to comply with the CO_2 emissions standard under part 60 using the same data currently collected under part 75.[117] However, many permitting authorities commented persuasively that the environmental benefits of using net-output-based standards can outweigh any additional complexities for particular units, and have indeed adopted net-output standards in recent GHG operating permits for combustion turbines. We expect this trend to continue and have concluded that it is appropriate to support the expanded use of net-output-based standards, and therefore are allowing certain sources to elect between gross output-based and net-output-based standards. Only combustion turbines are eligible to make this election.

The rule specifies an alternative net-output-based standard of 1,030 lb CO_2/MWh-n for combustion turbines. This standard is equivalent to the otherwise-applicable gross-output-based standard of 1,000 lb CO_2/MWh-g.[118]

The procedures for requesting this alternative net-output-based standard require the owner or operator to petition the Administrator in writing to comply with the alternate applicable net-output-based standard. If the Administrator grants the petition, this election would be binding and would be the unit's sole means of demonstrating compliance. Owners or operators complying with the net-output-based standard must similarly petition the Administrator to switch back to complying with the gross-output-based standard.

2. Useful Thermal Output

For CHP units, useful thermal output is also used when determining the emission rate. Previous rulemakings issued by the EPA have prescribed various ''discount factors'' of the measured useful thermal output to be used when determining the emission rate. We proposed that 75 percent credit is the appropriate discount factor for useful thermal output, and we solicited

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[117] Additionally, having an NSPS standard that is measured using the same monitoring equipment as required under the operating permit minimizes compliance burden. If a combustion turbine were subject to both a gross and net emission limit, more expensive higher accuracy monitoring could be required for both measurements.

[118] Assuming a 3 percent auxiliary load for the NGCC system.

comment on a range from two-thirds to three-fourths credit for useful thermal output in the proposal for newly constructed units and two-thirds to one hundred percent credit in the proposal for modified and reconstructed units. The 75 percent credit was based on matching the emission rate, but not the overall emissions, of a hypothetical CHP unit to the proposed emission rate.

Many commenters said that in order to fully account for the environmental benefits of CHP and to reflect the environmental benefits of CHP, the EPA should allow 100 percent of the useful thermal output from CHP units. Commenters noted that providing 100 percent credit for useful thermal output is consistent with the past practice of the EPA in the stationary combustion turbine criteria pollutant NSPS and state approaches for determining emission rates for CHP units.

Based on further consideration and review of the comments submitted, we are finalizing 100 percent credit for useful thermal output for all newly constructed, modified, and reconstructed CHP sources. We have concluded that this is appropriate because, at the same reported emission rate, a hypothetical CHP unit would have the same overall GHG emissions as the combined emission rate of separate heat and power facilities. Any discounting of useful thermal output could distort the market and discourage the development of new CHP units. Full credit for useful thermal output appropriately recognizes the environmental benefit of CHP.

G. CO_2 Emissions Only

The air pollutant regulated in this final action is greenhouse gases. However, the standards in this rule are expressed in the form of limits on only emissions of CO_2, and not the other constituent gases of the air pollutant GHGs.[119] We are not establishing a limit on aggregate GHGs or separate emission limits for other GHGs (such as methane (CH_4) or nitrous oxide (N_2O)) as other GHGs represent less than 1 percent of total estimated GHG emissions (as CO_2e) from fossil fuel-fired electric power generating units.[120] Notwithstanding this form of the standard, consistent with other EPA regulations addressing GHGs, the air pollutant regulated in this rule is GHGs.[121]

H. Legal Requirements for Establishing Emission Standards

1. Introduction

In the January 2014 proposal, we described the principal legal requirement for standards of performance under CAA section 111(b), which is that the standards of performance must consist of standards for emissions that reflect the degree of emission limitation achievable though the application of the ''best system of emission reduction . . . adequately demonstrated,'' taking into account cost and any non-air quality health and environment impact and energy requirements. We noted that the D.C. Circuit has handed down numerous decisions that interpret this CAA provision, including its component elements, and we reviewed that case law in detail.[122]

We received comments on our proposed interpretation, and in light of those comments, in this rule, we are clarifying our interpretation in certain respects. We discuss our interpretation below.[123]

2. CAA Requirements and Court Interpretation

As noted above, the CAA section 111 requirements that govern this rule are as follows: As the first step towards establishing standards of performance, the EPA ''shall publish . . . a list of categories of stationary sources . . . [that] cause[ ], or contribute[ ] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' CAA section 111(b)(1)(A). Following that listing, the EPA ''shall publish proposed regulations, establishing federal standards of performance for new sources within such category'' and then ''promulgate . . . such standards'' within a year after proposal. CAA section 111(b)(1)(B). The EPA ''may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.'' CAA section 111(b)(2). The term ''standard of performance'' is defined to ''mean[ ] a standard for emissions . . . achievable through the application of the best system of emission reduction which [considering cost, non-air quality health and environmental impact, and energy requirements] the Administrator determines has been adequately demonstrated.'' CAA section 111(a)(1).

As noted in the January 2014 proposal, Congress first included the definition of ''standard of performance'' when enacting CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), amended it in the 1977 CAAA, and then amended it again in the 1990 CAAA to largely restore the definition as it read in the 1970 CAAA. It is in the legislative history for the 1970 and 1977 CAAAs that Congress primarily addressed the definition as it read at those times, and that legislative history provides guidance in interpreting this provision.[124] In addition, the D.C. Circuit has reviewed rulemakings under CAA section 111 on numerous occasions during the past 40 years, handing down decisions dated from 1973 to 2011,[125] through which the

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[119] As noted above, in the Endangerment Finding, the EPA defined the relevant ''air pollution'' as the atmospheric mix of six long-lived and directly-emitted greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). 74 FR 66497.

[120] EPA Greenhouse Gas Reporting Program; *www.epa.gov/ghgreporting/.*

[121] See 77 FR 31257–30 (June 3, 2010).

[122] 79 FR 1430, 1462 (January 8, 2014).

[123] We also discuss our interpretation of the requirements for standards of performance and the BSER under section 111(d), for existing sources, in the section 111(d) rulemaking that the EPA is finalizing with this rule. Our interpretations and applications of these requirements in the two rulemakings are generally consistent with each other except to the extent that they reflect distinctions between new and existing sources. For example, the BSER for new industrial facilities, which are expected to have lengthy useful lives, should include, at a minimum, the most advanced pollution controls available, but for existing sources, the additional costs of retrofit may render those controls too expensive.

[124] In the 1970 CAAA, Congress defined ''standard of performance,'' under section 111(a)(1), as—a standard for emissions of air pollutants which reflects 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) the Administrator determines has been adequately demonstrated.

In the 1977 CAAA, Congress revised the definition to distinguish among different types of sources, and to require that for fossil fuel-fired sources, the standard: (i) Be based on, in lieu of the ''best system of emission reduction . . . adequately demonstrated,'' the ''best technological system of continuous emission reduction . . . adequately demonstrated;'' and (ii) require a percentage reduction in emissions. In addition, in the 1977 CAAA, Congress expanded the parenthetical requirement that the Administrator consider the cost of achieving the reduction to also require the Administrator to consider ''any nonair quality health and environment impact and energy requirements.''

In the 1990 CAAA, Congress again revised the definition, this time repealing the requirements that the standard of performance be based on the best technological system and achieve a percentage reduction in emissions, and replacing those provisions with the terms used in the 1970 CAAA version of section 111(a)(1) that the standard of performance be based on the ''best system of emission reduction . . . adequately demonstrated.'' This 1990 CAAA version is the current definition. Even so, because parts of the definition as it read under the 1977 CAAA were retained in the 1990 CAAA, the explanation in the 1977 CAAA legislative history, and the interpretation in the case law, of those parts of the definition in the case law remain relevant to the definition as it reads today.

[125] *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);

Continued

Court has developed a body of case law that interprets the term ''standard of performance.''

3. Key Elements of Interpretation

By its terms, the definition of ''standard of performance'' under CAA section 111(a)(1) provides that the emission limits that the EPA promulgates must be ''achievable'' by application of a ''system of emission reduction'' that the EPA determines to be the ''best'' that is ''adequately demonstrated,'' ''taking into account . . . cost . . . nonair quality health and environmental impact and energy requirements.'' The D.C. Circuit has stated that, in determining the ''best'' system, the EPA must also take into account ''the amount of air pollution'' [126] reduced and the role of ''technological innovation.'' [127] The Court has emphasized that the EPA has discretion in weighing those various factors.[128] [129]

Our overall approach to determining the BSER, which incorporates the various elements, is as follows: First, the EPA identifies the ''system[s] of emission reduction'' that have been ''adequately demonstrated'' for a particular source category. Second, the EPA determines the ''best'' of these systems after evaluating extent of emission reductions, costs, any non-air health and environmental impacts, and energy requirements. And third, the EPA selects an achievable standard for emissions—here, the emission rate—based on the performance of the BSER. The remainder of this subsection discusses the various elements in that analytical approach.

a. ''System[s] of Emission Reduction . . . Adequately Demonstrated''

The EPA's first step is to identify ''system[s] of emission reduction . . . adequately demonstrated.'' For the reasons discussed below, for the various types of newly constructed, modified, and reconstructed sources in this rulemaking, the EPA focused on efficient generation, add-on controls, efficiency improvements, and clean fuels as the systems of emission reduction.

An ''adequately demonstrated'' system, according to the D.C. Circuit, is ''one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' [130] It does not mean that the system ''must be in actual routine use somewhere.'' [131] Rather, the Court has said, ''[t]he Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry.'' [132] Similarly, the EPA may ''hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible.'' [133] Ultimately, the analysis ''is partially dependent on 'lead time,' '' that is, ''the time in which the technology will have to be available.'' [134] Per CAA section 111(e), standards of performance under CAA section 111(b) are applicable immediately after the effective date of their promulgation.

(1) Technical Feasibility of the Best System of Emission Reduction

As the January 2014 proposal indicates, the requirement that the standard for emissions be ''achievable'' based on the ''best system of emission reduction . . . adequately demonstrated'' indicates that one of the requirements for the technology or other measures that the EPA identifies as the BSER is that the measure must be technically feasible. See 79 FR 1430, 1463 (January 8, 2014).

b. ''Best''

In determining which adequately demonstrated system of emission reduction is the ''best,'' the EPA considers the following factors:

(1) Costs

Under CAA section 111(a)(1), the EPA is required to take into account ''the cost of achieving'' the required emission reductions. As described in the January 2014 proposal,[135] in several cases the D.C. Circuit has elaborated on this cost factor and formulated the cost standard in various ways, stating that the EPA may not adopt a standard the cost of which would be ''exorbitant,'' [136] ''greater than the industry could bear and survive,'' [137] ''excessive,'' [138] or ''unreasonable.'' [139] For convenience, in this rulemaking, we use 'reasonableness' to describe costs well within the bounds established by this jurisprudence.[140]

The D.C. Circuit has indicated that the EPA has substantial discretion in its consideration of cost under section 111(a). In several cases, the Court upheld standards that entailed significant costs, consistent with Congress's view that ''the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.'' [141] *See Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973); [142] *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375, 387–88 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir.

Portland Cement Ass'n v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011). *See also Delaware* v. *EPA,* No. 13–1093 (D.C. Cir. May 1, 2015).

[126] See *Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981).

[127] See *Sierra Club* v. *Costle,* 657 F.2d at 347.

[128] See *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[129] Although section 111(a)(1) may be read to state that the factors enumerated in the parenthetical are part of the ''adequately demonstrated'' determination, the D.C. Circuit's case law appears to treat them as part of the ''best'' determination. See *Sierra Club* v. *Costle,* 657 F.2d at 325–26. It does not appear that those two approaches would lead to different outcomes. In this rule, the EPA is following the D.C. Circuit case law and treating the factors as part of the ''best'' determination.

[130] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974).

[131] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted) (discussing the Senate and House bills and reports from which the language in CAA section 111 grew).

[132] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

[133] *Sierra Club* v. *Costle,* 657 F.2d 298, 364 (1981).

[134] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

[135] 79 FR 1464 (January 8, 2014).

[136] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[137] *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975).

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

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

[140] These cost formulations are consistent with the legislative history of section 111. The 1977 House Committee Report noted:

> In the [1970] Congress [*sic:* Congress's] view, it was only right that the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.

1977 House Committee Report at 184. Similarly, the 1970 Senate Committee Report stated:

> The implicit consideration of economic factors in determining whether technology is ''available'' should not affect the usefulness of this section. The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach.

S. Comm. Rep. No. 91–1196 at 16. Some commenters asserted that we do not have authority to revise the cost standard as established in the case law, *e.g.,* ''exorbitant,'' ''excessive,'' etc., to a ''reasonableness'' standard that may be considered less protective of the environment. We agree that we do not have authority to revise the cost standard as established in the case law, and we are not attempting to do so here. Rather, our description of the cost standard as ''reasonableness'' is intended to be a convenient term for referring to the cost standard as established in the case law.

[141] 1977 House Committee Report at 184.

[142] The costs for these standards were described in the rulemakings. *See* 36 FR 24876 (December 23, 1971), 37 FR 5767, 5769 (March 21, 1972).

1981) (upholding standard imposing controls on SO_2 emissions from coal-fired power plants when the ''cost of the new controls . . . is substantial'').[143] Moreover, section 111(a) does not provide specific direction regarding what metric or metrics to use in considering costs, again affording the EPA considerable discretion in choosing a means of cost consideration.[144]

As discussed below, the EPA may consider costs on both a source-specific basis and a sector-wide, regional, or nationwide basis. The EPA is finding here that whether costs are considered on a source-specific basis, an industry/national basis, or both, they are reasonable. See Sections V.H and I below.

(2) Non-Air Quality Health and Environmental Impacts

Under CAA section 111(a)(1), the EPA is required to take into account ''any nonair quality health and environmental impact'' in determining the BSER. As the D.C. Circuit has explained, this requirement makes explicit that a system cannot be ''best'' if it does more harm than good due to cross-media environmental impacts.[145] The EPA has carefully considered such cross-media impacts here, in particular potential impacts to underground sources of drinking water posed by CO_2 sequestration, and water use necessary to operate carbon capture systems. See Sections V.N and O below.

(3) Energy Considerations

Under CAA section 111(a)(1), the EPA is required to take into account ''energy requirements.'' As discussed below, the EPA may consider energy requirements on both a source-specific basis and a sector-wide, region-wide, or nationwide basis. Considered on a source-specific basis, ''energy requirements'' entail, for example, the impact, if any, of the system of emission reduction on the source's own energy needs. In this rulemaking, as discussed below in Section V.O.3, the EPA considered the parasitic load requirements of partial CCS. The EPA is finding here that whether energy requirements are considered on a source-specific basis, an industry/national basis, or both, they are reasonable. See Sections V.O.3 and XIII.C.

(4) Amount of Emissions Reductions

At proposal, we noted that although the definition of ''standard of performance'' does not by its terms identify the amount of emissions from the category of sources or the amount of emission reductions achieved as factors the EPA must consider in determining the ''best system of emission reduction,'' the D.C. Circuit has stated that the EPA must in fact do so. *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981) (''we can think of no sensible interpretation of the statutory words ''best . . . system'' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions'').[146] The fact that the purpose of a ''system of emission reduction'' is to reduce emissions, and that the term itself explicitly incorporates the concept of reducing emissions, supports the Court's view that in determining whether a ''system of emission reduction'' is the ''best,'' the EPA must consider the amount of emission reductions that the system would yield.[147] Even if the EPA were not required to consider the amount of emission reductions, the EPA has the discretion to do so, on grounds that either the term ''system of emission reduction'' or the term ''best'' may reasonably be read to allow that discretion.

(5) Sector or Nationwide Component of the BSER Factors

As discussed in the January 2014 proposal, another component of the D.C. Circuit's interpretations of CAA section 111 is that the EPA may consider the various factors it is required to consider on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking.[148] The D.C. Circuit based this conclusion on a review of the legislative history, stating,

> The Conferees defined the best technology in terms of ''long-term growth,'' ''long-term cost savings,'' effects on the ''coal market,'' including prices and utilization of coal reserves, and ''incentives for improved technology.'' Indeed, the Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111.[149]

The Court has upheld rules that the EPA ''justified . . . in terms of the policies of the Act,'' including balancing long-term national and regional impacts:

> The standard reflects a balance in environmental, economic, and energy consideration by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties. . . . By achieving a balanced coal demand within the utility sector and by promoting the development of less expensive SO_2 control technology, the final standard will expand environmentally acceptable energy supplies to existing power plants and industrial sources.
>
> By substantially reducing SO_2 emissions, the standard will enhance the potential for long term economic growth at both the national and regional levels.[150]

Some commenters objected that this case law did not allow the EPA to ignore source-specific impacts (particularly cost impacts) by basing determinations solely on impacts at a regional or national level. In fact, the EPA's consideration of cost, non-air quality impacts, and energy requirements reflect source-specific impacts, as well as (for some considerations) impacts that are sector-wide, regional, or national. See Section V.H.6 below.

c. Achievability of the Standard for Emissions

In the January 2014 proposal, the EPA recognized that the first element of the definition of ''standard of performance'' is that ''the emission limit [*i.e.,* the 'standard for emissions'] that the EPA promulgates must be 'achievable' ''

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[143] Indeed, in upholding the EPA's consideration of costs under the provisions of the Clean Water Act authorizing technology-based standards based on performance of a best technology taking costs into account, courts have also noted the substantial discretion delegated to the EPA to weigh cost considerations with other factors. *Chemical Mfr's Ass'n* v. *EPA,* 870 F.2d 177, 251 (5th Cir. 1989); *Association of Iron and Steel Inst.* v. *EPA,* 526 F.2d 1027, 1054 (3d Cir. 1975); *Ass'n of Pacific Fisheries* v. *EPA,* 615 F.2d 794, 808 (9th Cir. 1980).

[144] See, *e.g., Husqvarna AB* v. *EPA,* 254 F.3d 195, 200 (D.C. Cir. 2001) (where CAA section 213 does not mandate a specific method of cost analysis, the EPA may make a reasoned choice as to how to analyze costs).

[145] *Portland Cement* v. *EPA,* 486 F.2d at 384; *Sierra Club* v. *Costle,* 657 F.2d at 331; see also *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d at 439 (remanding standard to consider solid waste disposal implications of the BSER determination).

[146] *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of ''standard of performance,'' which revised the phrase ''best system'' to read, ''best *technological* system.'' As noted above, the 1990 CAAA deleted ''technological,'' and thereby returned the phrase to how it read under the 1970 CAAA. The court's interpretation of this phrase in *Sierra Club* v. *Costle* to require consideration of the amount of air emissions reductions remains valid for the phrase ''best system.''

[147] See also *NRDC* v. *EPA,* 479 F.3d 875, 880 (D.C. Cir. 2006) (''best performing'' source for purposes of CAA section 112 (d)(3) is source with the lowest emission levels).

[148] 79 FR 1430, 1465 January 8, 2014) (citing *Sierra Club* v. *Costle,* 657 F.2d at 351).

[149] *Sierra Club* v. *Costle,* 657 F.2d at 331 (citations omitted) (citing legislative history).

[150] *Sierra Club* v. *Costle,* 657 F.2d at 327–28 (quoting 44 FR 33583/3–33584/1). In the January 2014 proposal, we explained that although the D.C. Circuit decided *Sierra Club* v. *Costle* before the *Chevron* case was decided in 1984, the D.C. Circuit's decision could be justified under either *Chevron* step 1 or 2. 79 FR 1430, 1466 (January 8, 2014).

based on performance of the BSER. 79 FR 1430, 1463 (January 8, 2014). According to the D.C. Circuit, a standard for emissions is ''achievable'' if a technology can reasonably be projected to be available to new sources at the time they are constructed that will allow them to meet the standard.[151] Moreover, according to the Court, ''[a]n achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.'' [152] To be achievable, a standard ''must be capable of being met under most adverse conditions which can reasonably be expected to recur and which are not or cannot be taken into account in determining the 'cost of compliance.' '' [153] To show that a standard is achievable, the EPA must ''(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard.'' [154]

In Sections V.J and IX.D below, we show both that the BSER for new steam generating units and combustion turbines is technically feasible and adequately demonstrated, and that the standards of 1,400 lb CO_2/MWh-g and 1,000 lb CO_2/MWh-g are achievable considering the range of operating variables that affect achievability.

d. Expanded Use and Development of Technology

In the January 2014 proposal, we noted that the D.C. Circuit has made clear 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.'' [155]

The Court grounded its reading in the statutory text.[156] In addition, in the January 2014 proposal, we noted that the Court's interpretation finds additional support in the legislative history.[157] We also explained that the legislative history identifies three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (i) The development of technology that may be treated as the ''best system of emission reduction . . . adequately demonstrated'' under section 111(a)(1); (ii) the expanded use of the best demonstrated technology; and (iii) the development of emerging technology.[158] Even if the EPA were not required to consider technological innovation as part of its determination of the BSER, it would be reasonable for the EPA to consider it, either because technological innovation may be considered an element of the term ''best,'' or because the term ''best system of emission reduction'' is ambiguous as to whether technological innovation may be considered. The interpretation is likewise consistent with the evident purpose of section 111(b) to require new sources to maximize emission reductions using state-of-the-art means of control.

Commenters stated that the requirement to consider technological innovation does not authorize the EPA to identify as the BSER a technology that is not adequately demonstrated. The proposal did not, and we do not in this final rule, claim to the contrary. In any event, as discussed below, the EPA may justify the control technologies identified in this rule as the BSER even without considering the factor of incentivizing technological innovation or development.

e. Agency Discretion

As discussed in the January 2014 proposal, the D.C. Circuit has made clear that the EPA has broad discretion in determining the appropriate standard of performance under the definition in CAA section 111(a)(1), quoted above. Specifically, 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,'' [159] and emphasized that ''[t]he text gives the EPA broad discretion to weigh different factors in setting the standard.'' [160] In *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999), the Court reiterated:

> 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. . . . EPA's choice [of the 'best system'] will be sustained unless the environmental or economic costs of using the technology are exorbitant. . . . EPA [has] considerable discretion under section 111.[161]

f. Lack of Requirement That Standard Must Be Met by All Sources

In the January 2014 proposal, the EPA proposed that, under CAA section 111, an emissions standard may meet the requirements of a ''standard of performance'' even if it cannot be met by every new source in the source category that would have constructed in the absence of that standard. As described in the January 2014 proposal, the EPA based this view on (i) the legislative history of CAA section 111, read in conjunction with the legislative history of the CAA as a whole; (ii) case law under analogous CAA provisions; and (iii) long-standing precedent in the EPA rulemakings under CAA section 111.[162]

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[151] *Portland Cement,* 486 F.2d at 391–92. Some commenters stated that the EPA's analysis of the requirements for ''standard of performance,'' including the BSER, attempted to eliminate the requirement that the standard for emissions must be ''achievable.'' We disagree with this comment. As just quoted, the EPA's analysis recognizes that the standard for emissions must be achievable through the application of the BSER.

[152] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433–34 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974).

[153] *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433, n.46 (D.C. Cir. 1980).

[154] *Sierra Club* v. *Costle,* 657 F.2d 298, 377 (D.C. Cir. 1981) (citing *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416 (D.C. Cir. 1980). In considering the representativeness of the source tested, the EPA may consider such variables as the '''feedstock, operation, size and age' of the source.'' *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433 (D.C. Cir. 1980). Moreover, it may be sufficient to ''generalize from a sample of one when one is the only available sample, or when that one is shown to be representative of the regulated industry along relevant parameters.'' *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 434, n.52 (D.C. Cir. 1980).

[155] See 79 FR 1430, 1465 (January 8, 2014), *Sierra Club* v. *Costle,* 657 F.2d at 346–47.

[156] *Sierra Club* v. *Costle,* 657 F.2d at 346 (''Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and nonair quality health and environmental factors embraces consideration of technological innovation as part of that balance. The statutory factors which the EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation.'').

[157] *See* 79 FR 1430, 1465 (January 8, 2014) (citing S.Rep. 91–1196 at 16 (1970)) (''Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources''); S. Rep. 95–127 at 17 (1977) (cited in *Sierra Club* v. *Costle,* 657 F.2d at 346 n. 174) (''The section 111 Standards of Performance . . . sought to assure the use of available technology and to stimulate the development of new technology'').

[158] 79 FR 1465 (citing case law and legislative history).

[159] *Sierra Club* v. *Costle,* 657 F.2d at 319.

[160] *Sierra Club* v. *Costle,* 657 F.2d at 321; see also *New York* v. *Reilly, 969 F. 2d at 1150* (because Congress did not assign the specific weight the Administrator should assign to the statutory elements, ''the Administrator is free to exercise [her] discretion'' in promulgating an NSPS).

[161] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) (paragraphing revised for convenience). *See also NRDC* v. *EPA,* 25 F.3d 1063, 1071 (D.C. Cir. 1994) (The EPA did not err in its final balancing because ''neither RCRA nor EPA's regulations purports to assign any particular weight to the factors listed in subsection (a)(3). That being the case, the Administrator was free to emphasize or deemphasize particular factors, constrained only by the requirements of reasoned agency decision making.'').

[162] 79 FR 1430, 1466 (January 8, 2014).

Commenters contested this assertion, arguing that a 111(b) standard must be achievable by all new sources. We continue to take the same position as at proposal for the reasons described there. We note that as a practical matter, in this rulemaking, the issue of whether all new steam-generating sources can implement partial-capture CCS is largely dependent on the geographic scope of geologic sequestration sites. As discussed below in Section V.M, geologic sequestration sites are widely available, and a steam-generating plant with partial CCS that is sited near an area that is suitable for geologic sequestration can serve demand in a large area that may not have sequestration sites available. In any event, the standard of 1,400 lb CO_2/MW-g that we promulgate in this final rule can be achieved by new steam generating EGUs—including new utility boilers and IGCC units—through co-firing with natural gas in lieu of installing partial CCS, which moots the issue of the geographic availability of geologic sequestration.

g. EPAct05

The Energy Policy Act of 2005 (''EPAct05'') authorizes assistance in the form of grants, loan guarantees, as well as federal tax credits for investment in ''clean coal technology.'' Sections 402(i), 421(a), and 1307(b) (adding section 48A(g) to the Internal Revenue Code (''IRC'')) address the extent to which information from clean coal projects receiving assistance under the EPAct05 may be considered by the EPA in determining what is the best system of emission reduction adequately demonstrated. Section 402(i) of the EPAct05 limits the use of information from facilities that receive assistance under EPAct05 in CAA section 111 rulemakings:

> ''No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be adequately demonstrated [ ] for purposes of section 111 of the Clean Air Act. . . .'' [163]

IRC section 48A(g) contains a similar constraint concerning the use of technology or level of emission reduction from EGU facilities for which a tax credit is allowed:

> ''No use of technology (or level of emission reduction solely by reason of the use of the technology), and no achievement of any emission reduction by the demonstration of any technology or performance level, by or at one or more facilities with respect to which a credit is allowed under this section, shall be considered to indicate that the technology or performance level is adequately demonstrated [ ] for purposes of section 111 of the Clean Air Act. . . .''

The EPA specifically solicited comment on its interpretation of these provisions. 79 FR 10750 (Feb. 26, 2014) (Notice of Data Availability). With respect to EPAct05 sections 402(i) and 421(a), the EPA proposed that these provisions barred consideration where EPAct05-assisted facilities were the sole support for the BSER determination, but that these sources could support a BSER determination so long as there is additional evidence supporting the determination.[164] In addition, the EPA viewed the two prohibitions as relating only to the technology or emissions reduction for which assistance was given.[165] The EPA likewise interpreted IRC section 48A(g)—based on the plain language and the context provided by sections 402(i) and 421(a)—to mean that use of technology, or emission performance, from a facility for which the credit is allowed cannot, by itself, support a finding that the technology or performance level is adequately demonstrated, but the information can corroborate an otherwise supported determination or otherwise provide part of the basis for such a determination.[166] The EPA also proposed to interpret the phrase ''with respect to which a credit is allowed under this section'' as referring to the entire phrase ''use of technology (or level of emission reduction . . .) and [] achievement of any emission reduction . . . , by or at one or more facilities.'' Thus, if technology A received a tax credit, but technology B at the same facility did not, the constraint would not apply to technology B.[167]

Some commenters supported the EPA's proposed interpretation. Others contended that the EPA's interpretation would allow it to support a BSER determination even where EPAct05 facility information comprised 99 percent of the supporting information for a BSER determination because that determination would not be based ''solely'' on EPAct05 sources. These commenters urged the EPA to conclude that a determination ''solely'' on the basis of information from EPAct05-assisted facilities is any determination where ''but for'' that information, the EPA could not justify its chosen standard as the BSER.[168] Other commenters argued that the provisions bar the EPA from all consideration of EPAct05 facilities when determining that a technology or level of performance is adequately demonstrated.

In this final rule, the EPA is adopting the interpretations of all three provisions that it proposed, largely for the reasons previously advanced. The EPA thus interprets these provisions to preclude the EPA from relying solely on the experience of facilities that received DOE assistance, but not to preclude the EPA from relying on the experience of such facilities in conjunction with other information. This reading of sections 402(i) and 421(a) is consistent with the views of the only court to date to consider the matter.[169]

The EPA notes that the extreme hypothetical posed in the comments (where the EPA might avoid a limitation on its consideration of EPAct05-assisted facilities by including a mere scintilla of evidence from non-EPAct05 facilities) is not presented here, where the principal evidence that partial post-combustion CCS is a demonstrated and feasible technology comes from sources which received no assistance of any type under EPAct05. The EPA also concludes that the ''but for'' test urged by these commenters is an inappropriate reading of the term ''solely'' in sections 402(i) and 421(a), as any piece of evidence may be a necessary, or ''but for,'' cause without being a sufficient, or ''sole,'' cause.[170] Nonetheless, if the ''but for'' test were applicable here, the available evidence would satisfy it.

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[163] Codified at 42 U.S.C. 15962(a). EPAct05 section 421(a) similarly states: ''No technology, or level of emission reduction, shall be treated as adequately demonstrated for purpose [sic] of section 7411 of this title, . . . solely by reason of the use of such technology, or the achievement of such emission reduction, by one or more facilities receiving assistance under section 13572(a)(1) of this title''.

[164] Technical Support Document, *Effect of EPAct05 on Best System of Emission Reduction for New Power Plants,* p. 6 (Docket entry: EPA–HQ–OAR–2013–0495–1873).

[165] Id.

[166] Id. p. 13.

[167] Id. p. 14.

[168] Comments of AFPM/API p. 46 (Docket entry: EPA–HQ–OAR–2013–0495–10098).

[169] *State of Nebraska* v. *EPA,* 2014 U.S. Dist. LEXIS 141898 at n. 1 (D. Nebr. 2014). (''But the Court notes that § 402(i) only forbids the EPA from considering a given technology or level of emission reduction to be adequately demonstrated *solely* on the basis of federally-funded facilities. 42 U.S.C. 15962(i). In other words, such technology might be adequately demonstrated if that determination is based at least in part on non-federally-funded facilities'') (emphasis original).

[170] For example, any vote of a Justice on the Supreme Court may be a necessary but not sufficient cause. In a 5–4 decision, the decision of the Court would have been different ''but for'' the assent of Justice A or Justice B, who were in the majority. But it would be incorrect to say that the assent of Justice A was the ''sole'' reason for the outcome, when the decision also required the assent of Justice B.

Other commenters took the extreme position that the EPAct05 provisions bar all consideration of a facility's existence if the facility received EPAct05 assistance.[171] The EPA does not accept this argument because it is contrary to both the plain statutory language[172] (see Chapter 2 of the Response-to-Comment document) and to Congress's intent that the EPAct05 programs advance the commercialization of clean coal technology. For the same reason, the EPA does not accept some commenters' suggestion that sections 402(i), 421(a), and 48A(g) preclude the EPA from considering NETL's cost projections for CCS, which base cost estimates on up-to-date vendor quotes reflecting costs for the CCS technology being utilized at the Boundary Dam Unit #3 facility (a facility receiving no assistance under EPAct05), but also considers that to-be-built plants will no longer be first-of-a kind. See generally Section V.I.2 below. Commenters suggest that the EPAct05 requires that the EPA treat future plants as ''first of a kind'' when projecting costs, as if EPAct05 facilities simply did not exist. This reading is contrary to the text of the provisions, which as noted, relates specifically to a source's performance and operation (whether a technology is demonstrated, and the level of performance achieved by use of technology), not to sources' existence. NETL's cost projections, on the other hand, merely acknowledge the evident fact that CCS technologies exist, and reasonably project that they will continue to develop. See Section V.I.2. The NETL cost estimates, moreover, are based on vendor quotes for the CCS technology in use at the Boundary Dam facility, a Canadian plant which obviously is not a recipient of EPAct05 assistance. See sections V.D.2.a and V.I.2 below.

In any case, as shown in Section V below, the EPA finds that a new highly-efficient SCPC EGU implementing partial post-combustion CCS is the best system of emission reduction adequately demonstrated and is doing so based in greater part on performance of facilities receiving no assistance under EPAct05, and on other information likewise not having any connection to EPAct05 assistance. The corroborative information from EPAct05 facilities, though supportive, is not necessary to the EPA's findings.

I. Severability

This rule has numerous components, and the EPA intends that they be severable from each other to the extent that they function separately. For example, the EPA intends that each set of BSER determinations and standards of performance in this rulemaking be severable from each other set. That is, the BSER determination and standard of performance for newly constructed fossil fuel-fired electric utility steam generating units are severable from all the other BSER determinations and standards of performance, and the same is true for the BSER determination and standard of performance for modified fossil fuel-fired electric utility steam generating units, and so on. It is reasonable to consider each set of BSER determination and standard of performance to be severable from each other set of BSER determination and standard of performance because each set is independently justifiable and does not depend on any other set. Thus, in the event that a court should strike down any set of BSER determination and standard of performance, the remaining BSER determinations and standards of performance should not be affected.

J. Certain Projects Under Development

In the January 2014 proposal, the EPA indicated that the proposed Wolverine EGU project (Rogers City, Michigan) appeared to be the only fossil fuel-fired steam generating unit that was currently under development that may be capable of ''commencing construction'' for NSPS purposes at the time of the proposal. See 79 FR 1461. The EPA also acknowledged that the Wolverine EGU, as designed, would not meet the proposed standard of 1,100 lb CO_2/MWh for new utility steam generating EGUs. The EPA proposed that, at the time of finalization of the proposed standards, if the Wolverine project remains under development and has not either commenced construction or been canceled, we anticipated proposing a standard of performance specifically for that facility. Additional discussion of the approach can be found in the proposal or in the technical support document in the docket entitled ''Fossil Fuel-Fired Boiler and IGCC EGU Projects under Development: Status and Approach.''

In December 2013—after the proposed action was signed, but before it was published—Wolverine Power Cooperative announced that it was cancelling construction of the proposed coal-fired power plant in Rogers City, MI.[173] Therefore, we are not finalizing the proposed exclusion for that project.

In the January 2014 proposal, the EPA also identified two other fossil fuel-fired steam generating EGU projects that, as currently designed, would not meet the proposed 1,100 lb CO_2/MWh emissions standard—the Plant Washington project in Georgia and the Holcomb 2 project in Kansas. We indicated that, at the time of the proposal, those projects appeared to remain under development but that the project developers had represented that the projects have commenced construction for NSPS purposes and, thus, would not be new sources subject to the proposed or final NSPS. Based solely on the developers' representations, the EPA indicated that those projects, if ultimately fully constructed, would be existing sources, and would thus not be subject to the standards of performance in this final action.

To date, neither developer has sought a formal EPA determination of NSPS applicability. As we specified in the January 2014 proposal—and we reiterate here—if such an applicability determination concludes that either the Plant Washington (GA) project or the Holcomb 2 (KS) project did not commence construction prior to January 8, 2014 (the publication of the January 2014 proposal), then the project should be situated similarly to the disposition the EPA proposed for the Wolverine project. Accordingly, the EPA is finalizing in this action that if it is determined that either of these projects has not commenced construction as January 8, 2014, then that project will be addressed in the same manner as was proposed for the Wolverine project.

In public comments submitted in response to the January 2014, Power4Georgians (P4G), the Plant Washington developer, reiterated that they had executed binding contracts for the purchase and erection of the facility boiler prior to publication of the January 2014 proposal and believe that the binding contracts are sufficient to constitute commencement of construction for purposes of the NSPS program, so that they are existing rather than new sources for purposes of this

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[171] Supplemental Comments of Murray Energy p. 11 (Docket entry: EPA–HQ–OAR–2013–0495–9498).

[172] With respect to sections 402(i) and 421(a), commenters fail to reconcile their reading of the statute with the Act's grammatical structure, as explained in detail in chapter 2 of the Response-to-Comment document. One commenter supported its reading by adding suggested text to the statutory language, a highly disfavored form of statutory construction. Comments of UARG, p.124 n.38 (Docket entry: EPA–HQ–OAR–2013–0495–9666). With respect to section 48A(g), commenters misread the phrase ''considered to indicate,'' and do not explain how their reading of all three provisions together is tenable.

[173] ''Wolverine ends plant speculation in Rogers City'', The Alpena News, December 17, 2013. *http://www.thealpenanews.com/page/content.detail/id/527862/Wolverine-ends-plant-speculation-in-Rogers-City.html?nav=5004.*

rule.[174] Public comments submitted by Tri-State Generation and Transmission Association and Sunflower Electric Power Corporation, the developers of the Holcomb 2 project, discussed the cost incurred in the development of the project. They also indicated they had awarded contracts for the turbine/generator purchase and had negotiated a rail-supply agreement that provides for the delivery of fuel to the proposed Holcomb 2 site. The developers did not, however, explicitly characterize the construction status of the project.[175] Other groups submitted comments contending that neither project has actually commenced construction.

In October 2013, the Kansas Supreme Court invalidated the 2010 air pollution permit granted to Sunflower Electric Power Corporation by the Kansas Department of Health and Environment (KDHE).[176] In May 2014, the KDHE issued an air quality permit addendum for the proposed Holcomb 2 coal plant. The addendum addressed federal regulations that the Kansas Supreme Court held had been overlooked in the initial permitting determination. In June 2014, the Sierra Club filed an appeal with the Kansas Appellate Court challenging the legality of the May 2014 permit. Since the publication of the January 2014 proposal, the EPA is unaware of any physical construction activity at the proposed Holcomb 2 site.

In October 2014, the Plant Washington project was given an 18-month air permit extension by the Georgia Environmental Protection Division (EPD). However, as with the Holcomb expansion project, the EPA is unaware of any physical construction that has taken place at the proposed Plant Washington site and a recent audit of the project described it as ''dormant''.[177]

Based on this information, it appears that these sources have not commenced construction for purposes of section 111(b) and therefore would likely be new sources should they actually be constructed. As noted above, the EPA proposed that, if these projects are determined to not have commenced construction for NSPS purposes prior to the publication of the proposed rule, they will be addressed in the same manner proposed for the Wolverine project. 79 FR 1461. We are finalizing that proposal here. However, because these units may never actually be fully built and operated, we are not promulgating a standard of performance at this time because such action may prove to be unnecessary.[178]

There is one possible additional new EGU, the Two Elk project in Wyoming. In a supporting TSD accompanying the January 2014 proposal, we discussed the Two Elk project and relied on developer statements and state acquiescence that the unit had commenced construction for NSPS purposes before January 8, 2014.[179] We did not, therefore, propose any special section 111(b) standard for the project. Some commenters maintained that a continuous program of construction at the facility has not been maintained and that if the plant is ultimately constructed, it should be classified as a new source under CAA section 111(b). These comments were not specific enough to change the EPA's view of the project for purposes of this rulemaking. We accordingly continue to rely on developer statements that this facility has commenced construction and would not be a new source for purposes of this proceeding.

IV. Summary of Final Standards for Newly Constructed, Modified, and Reconstructed Fossil Fuel-Fired Electric Utility Steam Generating Units

This section sets forth the standards for newly constructed, modified, and reconstructed steam generating units (*i.e.,* utility boilers and IGCCs). We explain the rationale for the final standards in Sections V (newly constructed steam generating unit), VI (modified steam generating units), and VII (reconstructed steam generating units).

A. Applicability Requirements and Rationale

We generally refer to fossil fuel-fired electric utility generating units that would be subject to an emission standard in this rulemaking as ''affected'' or ''covered'' sources, units, facilities or simply as EGUs. These units meet both the definition of ''affected'' and ''covered'' EGUs subject to an emission standard as provided by this rule, and the criteria for being considered ''new,'' ''modified'' or ''reconstructed'' sources as defined under the provisions of CAA section 111 and the EPA's regulations. This section discusses applicability for newly constructed, modified, and reconstructed steam generating units.

1. General Applicability Criteria

The EPA is finalizing applicability criteria for new, modified, and reconstructed electric utility steam generating units (*i.e.,* utility boilers and IGCC units) in 40 CFR part 60, subpart TTTT that are similar to the applicability criteria for those units in 40 CFR part 60, subpart Da (utility boiler and IGCC performance standards for criteria pollutants), but with some differences. The proposed applicability criteria, relevant comments, and final applicability criteria specific to newly constructed, modified, and reconstructed steam generating units are discussed below.

The applicability requirements in the proposal for newly constructed EGUs included that a utility boiler or IGCC unit must: (1) Be capable of combusting more than 250 MMBtu/h heat input of fossil fuel; (2) be constructed for the purpose of supplying, and actually supply, more than one-third of its potential net-electric output capacity to any utility power distribution system (that is, to the grid) for sale on an annual basis; (3) be constructed for the purpose of supplying, and actually supply, more than 219,000 MWh net-electric output to the grid on an annual basis; and (4) combust over 10 percent fossil fuel on a heat input basis over a 3-year average. At proposal, applicability was determined based on a combination of design and actual operating conditions that could change annually depending on the proportion and the amount of electricity actually sold and on the proportion of fossil fuels combusted by the unit.

In the proposal for modified and reconstructed EGUs, we proposed a broader applicability approach such that applicability would be based solely on design criteria and would be identical to the applicability requirements in

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[174] Docket entry: EPA–HQ–OAR–2013–0495–9403.

[175] Docket entry: EPA–HQ–OAR–2013–0495–9599.

[176] ''Kansas High Court Invalidates 895–MW Coal Project Air Permit'', Power Magazine, 10/10/2013, available at: *www.powermag.com/kansas-high-court-invalidates-2010-895-mw-coal-project-air-permit/.*

[177] *http://www.macon.com/2015/06/23/3811798/audit-sandersville-coal-plant.html.*

[178] In the proposed emission guidelines for existing EGUs, the EPA did not include estimates of emissions for either Plant Washington or the Holcomb 2 unit in baseline data used to calculate proposed state goals for Georgia and Kansas. It appears that the possibility of these plants actually being built and operating is too remote. If either unit eventually seeks an applicability determination and that unit is determined to be an existing source, and there is reliable evidence that the source will operate, then the source will be subject to the final 111(d) rule and the EPA will allow the state to adjust its state goal to reflect adjustment of the state's baseline data so as to include the unit. Guidance for adjustment of state goals is provided in the record for the EPA's final CAA section 111(d) rulemaking.

[179] ''Fossil Fuel-Fired Boiler and IGCC EGU Projects Under Development: Status and Approach'', Technical Support Document at pp. 10–1 (Docket Entry: EPA–HQ–OAR–2013–0495–0024).

subpart Da. First, we proposed electric sales criteria that the source be constructed for the purpose of selling more than one-third of their potential electric output and more than 219,000 MWh to the grid on an annual basis, regardless of the actual amount of electricity sold (*i.e.,* we did not include the applicability criterion that the unit actually sell the specified amount of electricity on an annual basis). In addition, we proposed a base load rating criterion that the source be capable of combusting more than 250 MMBtu/h of fossil fuel, regardless of the actual amount of fossil fuel burned (*i.e.,* we did not include the fossil fuel-use criterion that an EGU actually combust more than 10 percent fossil fuel on a heat input basis on a 3-year average). Under this approach, applicability would be known prior to the unit actually commencing operation and would not change on an annual basis. We also proposed that the final applicability criteria would be consistent for newly constructed, reconstructed, and modified units. The proposed broad applicability criteria would still not have included boilers and IGCC units that were constructed for the purpose of selling one-third or less of their potential output or 219,000 MWh or less to the grid on an annual basis. These units are not covered under subpart Da (the utility boiler and IGCC EGU criteria pollutant NSPS) but are instead covered as industrial boilers under subpart Db (industrial, institutional, and commercial boilers NSPS) or subpart KKKK (the combustion turbine criteria pollutant NSPS).

We solicited comment on whether, to avoid implementation issues related with different interpretations of ''constructed for the purpose,'' the total and percentage electric sales criteria should be recast to be based on permit conditions. The ''constructed for the purpose'' language was included in the original subpart Da rulemaking. At that time, the vast majority of new steam generating units were clearly base load units. The ''constructed for the purpose'' language was intended to exempt industrial CHP units. These units tend to be relatively small and were not the focus of the rulemaking. In addition, units not meeting the electric sales applicability criteria in subpart Da would be covered by other NSPS so there is limited regulatory incentive, or impact to the environment, for owners/operators to avoid applicability with the utility NSPS. However, for new units, there is no corresponding industrial unit CO_2 NSPS and existing units could debate their original intent (*i.e.,* the purpose for which they were constructed) in an attempt to avoid applicability under section 111(d) requirements. Consequently, there could be a regulatory incentive for owners/operators to circumvent the CO_2 NSPS applicability. For units that avoid coverage, there would also be a corresponding environmental impact. For example, an owner/operator of a new unit could initially request a permit restriction to limit electric sales to less than one-third of potential annual electric output, but amend the operating permit shortly after operation has commenced to circumvent the intended applicability. Many existing units were initially built with excess capacity to account for projected load growth and were intended to sell more than one-third of their potential electric output. However, due to various factors (lower than expected load growth, availability of other lower cost units, etc.), certain units might have sold less than one-third of their potential electric output, at least during their initial period of operation. Therefore, the EPA has concluded that determining applicability based on whether a unit is ''*constructed for the purpose of* supplying one-third or more of its potential electric output and more than 219,000 MWh as net-electric sales'' (emphasis added) could create applicability uncertainty for both the regulated community and regulators. In addition, we have concluded that applicability based on actual operating conditions (*i.e.,* actual electric sales) is not ideal because applicability would not be known prior to determining compliance and could change annually.

This action finalizes applicability criteria based on design characteristics and federally enforceable permit restrictions included in each individual permit. Based on restrictions, if any, on annual total electric sales in the operating permit, it will be clear from the time of construction whether or not a new unit is subject to this rule. The applicability includes all utility boilers and IGCC units unless the electric sales restriction was in the original and remains in the current operating permit without any lapses (this is to be consistent with the 'constructed for the purpose of' criteria in subpart Da). We have concluded that this approach is equivalent to, but clearer than, the existing language used in subpart Da. In addition, we have concluded that it is important for both the 111(b) and 111(d) requirements for electric-only steam generating units that the permit restriction limiting annual electric sales be included in both the original and current operating permit. Without this restriction, existing units could avoid obligations under state plans developed as part of the 111(d) program by amending their operating permit to limit total annual electric sales to one-third of potential electric output. These units would not be subject to any GHG NSPS requirements because they would not meet the 111(b) or 111(d) applicability criteria and, at this time, there is no NSPS that would cover these units. As described in Section III, industrial CHP and dedicated non-fossil units also are not affected EGUs under this final action.

In this rule, we are finalizing the definition of a steam generating EGU as a utility boiler or IGCC unit that: (1) Has a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel) and (2) serves a generator capable of supplying more than 25 MW-net to a utility distribution system (*i.e.,* for sale to the grid). However, we are not establishing final CO_2 standards for certain EGUs. These include: (1) Steam generating units and IGCC units that are currently subject to—and have been continuously subject to—a federally enforceable permit limiting annual electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less; (2) units subject to a federally enforceable permit that limits the use of fossil fuels to 10 percent or less of the unit's heat input capacity on an annual basis; and (3) CHP units that are subject to a federally enforceable permit condition limiting annual total electric sales to no more than their design efficiency times their potential electric output, or to no more than 219,000 MWh, whichever is greater.

2. Applicability Specific to Newly Constructed Steam Generating Units

In CAA section 111(a)(2), a ''new source'' is defined as any stationary source, the construction or modification of which is commenced after the publication of regulations (or if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source. Accordingly, for purposes of this rule, a newly constructed steam generating EGU is a unit that fits the definition and applicability criteria of a fossil fuel-fired steam generating EGU and commences construction on or after January 8, 2014, which is the date that the proposed standards were published for those sources (see 79 FR 1430).

3. Applicability Specific to Modified Steam Generating Units

In CAA section 111(a)(4), a ''modification'' is defined as ''any physical change in, or change in the method of operation of, a stationary source'' that either ''increases the amount of any air pollutant emitted by such source or . . . results in the emission of any air pollutant not previously emitted.'' The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.[180]

For purposes of this rule, a modified steam generating EGU is a unit that fits the definition and applicability criteria of a fossil fuel-fired steam generating EGU and that modifies on or after June 18, 2014, which is the date that the proposed standards were published for those sources (see 79 FR 34960).

4. Applicability Specific to Reconstructed Steam Generating Units

The NSPS general provisions (40 CFR part 60, subpart A) provide that an existing source is considered a new source if it undertakes a ''reconstruction,'' which is the replacement of components of an existing facility to an extent 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.[181]

For purposes of this rule, a reconstructed steam generating EGU is a unit that fits the definition and applicability criteria of a fossil fuel-fired steam generating EGU and that reconstructs on or after June 18, 2014, which is the date that the proposed standards were published for those sources (see 79 FR 34960).

B. Best System of Emission Reduction

1. BSER for Newly Constructed Steam Generating Units

In the January 2014 proposal, the EPA proposed that highly efficient new generation technology implementing partial CCS is the BSER for GHG emissions from new steam generating EGUs. (See generally 79 FR 1468–1469.) In this final action, the EPA has determined that the BSER for newly constructed steam generating units is a new highly efficient supercritical pulverized coal (SCPC) boiler implementing partial CCS technology to the extent of removal efficiency that meets a final emission limitation of 1,400 lb CO_2/MWh-g. The final standard of performance is less stringent than the proposed emission limitation of 1,100 lb CO_2/MWh-g. This change, as will be discussed in greater detail later in this preamble, is in response to public comments and reflects both a re-examination of the potential BSER technologies and the most recent, reliable information regarding technology costs. A newly constructed fossil fuel-fired supercritical utility boiler will be able to meet the final standard by implementing post-combustion carbon capture treating a slip-stream of the combustion flue gas. Alternative potential compliance paths are to build a new IGCC unit and co-fire with natural gas (or use pre-combustion carbon capture on a slip-stream), or for a supercritical utility boiler to co-fire with natural gas.

The EPA of course realizes that the final standard of performance (1,400 lb CO_2/MWh-g) differs from the proposed standard (1,100 lb CO_2/MWh-g). The EPA notes further, however, that the methodology for determining the final standard of performance is identical to that at proposal—determining that a new highly efficient generating technology implementing some degree of partial CCS is the BSER, with that degree of implementation being determined based on the reasonableness of costs. A key means of assessing the reasonableness of cost at proposal was comparison of the levelized cost of electricity (LCOE) with that of other dispatchable, base load non-NGCC generating options. We have maintained that approach in identifying BSER for the final standard. Applying this methodology to the most recent cost information has led the EPA to adopt the final standard of performance of 1,400 lb CO_2/MWh-g. See Section V.H at Table 8 below. This final standard reflects the level of emission reduction achievable by a highly efficient SCPC implementing the degree of partial CCS that remains cost comparable to the other non-NGCC dispatchable base load generating options.

The BSER for newly constructed steam generating EGUs in the final rule is very similar to that in the proposal. In this final action, the EPA finds that a highly efficient new SCPC EGU implementing partial CCS to the degree necessary to achieve an emission of 1,400 lb CO_2/MWh-g is the BSER. Contrary to the January 2014 proposal, the EPA finds that IGCC technology—either alone or implementing partial CCS—is not part of the BSER, but rather is a viable alternative compliance option. As noted at proposal, a BSER typically advances performance of a technology beyond current levels of performance. 79 FR 1465, 1471. Similarly, promotion of technology innovation can be a relevant factor in BSER determinations. Id. and Section III.H.3.d above. For these reasons, the EPA at proposal voiced concerns about adopting standards that would allow an IGCC to comply without utilizing CCS for slip-stream control. Id. at 1471. The final standard of 1,400 lb CO_2/MWh-g, adopted as a means of assuring reasonableness of costs, allows IGCC units to comply without using partial CCS. Thus, although the standard can be met by a highly efficient new IGCC unit using approximately 3 percent partial CCS (see Sections V.E and V.H.7 below), the EPA does not believe that implementation of partial CCS at such a low level, while technically feasible, is the option that utilities and project developers will choose. The EPA believes that IGCC project developers will either choose to meet the final standard by co-firing with natural gas—which would be a less costly and very straightforward process for a new IGCC unit—or they will choose to install CCS equipment that will allow the facility to achieve much deeper CO_2 reductions than required by this rule—likely to co-produce chemicals and/or to capture large volumes of CO_2 for use in EOR operations. Similarly, project developers may also—as an alternative to utilizing partial CCS technology—meet the final standard by co-firing approximately 40 percent natural gas in a new highly efficient SCPC EGU.

While the EPA does not find that IGCC technology—either alone or with implementation of partial CCS—is part of the BSER for new steam generating EGUs, we remain convinced that it is technically feasible (see Section V.E below) and believe that it represents a viable alternative compliance option that some project developers will consider to meet the final standard issued in this action. The EPA notes further that IGCC is available at reasonable cost (see Table 9 below), and involves use of an advanced technology. So, although the final standard reflects performance of a BSER which includes partial CCS, even in the instances that a compliance alternative might be utilized, that alternative would both result in emission reductions consistent with use of the BSER, and would reflect many of the underlying principles and attributes of the BSER (costs are both reasonable, not greatly dissimilar than BSER, no collateral adverse impacts on health or the environment, and reflects

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[180] 40 CFR 60.2, 60.14(e).

[181] 40 CFR 60.15.

performance of an advanced technology).

In reaching the final standard of performance, the EPA is aware that at proposal, the agency stated that it was not ''currently considering'' a standard of performance as high as 1,400 lb CO_2/MWh-g. 79 FR 1471. However, in that same discussion, the EPA noted the reasons for its reservations (chiefly reservations about the extent of emission reductions, promotion of advanced CO_2 control technologies, and whether the standard could be met by either utility boilers or IGCC units co-firing with natural gas, or otherwise complying without utilizing partial CCS), and we specifically solicited comment on the issue: ''We request that commenters who suggest emission rates above 1,200 lb CO_2/MWh address potential concerns about providing adequate reductions and technology development to be considered BSER.'' Id. The proposal thus both solicited comment on higher emission standards (including 1,400 lb CO_2/MWh-g based on a less aggressive rate of partial CCS), and provided ample notice of the methodology the EPA would use to determine the final BSER and the corresponding final standard.[182] For these reasons, the EPA believes that it provided adequate notice of this potential outcome at proposal, that the final standard of performance was reasonably foreseeable, and that the final standard is a logical outgrowth of the proposed rule. *Allina Health Services* v. *Sebelius,* 746 F. 3d 1102, 1107 (D.C. Cir. 2014).

A more detailed discussion of the rationale for the final BSER determination and of other systems that were also considered is provided in Section V.P of this preamble.[183]

2. BSER for Modified Steam Generating Units

The EPA has determined that, as proposed, the BSER for steam generating units that trigger the modification provisions is the modified unit's own best potential performance. However, as explained below, the final BSER determination and the scope of modifications to which the final standards apply differ in some important respects from what the EPA proposed.

The EPA proposed that the modified unit's best potential performance would be determined depending upon when the unit implemented the modification (*i.e.,* before or after being subject to an approved CAA section 111(d) state plan). For units that commenced modification prior to becoming subject to an approved CAA section 111(d) state plan, the EPA proposed unit-specific standards consistent with each modified unit's best one-year historical performance (during the years from 2002 to the time of the modification) plus an additional two percent reduction. For sources that commenced modification after becoming subject to an approved CAA section 111(d) plan, the EPA proposed that the unit's best potential performance would be determined from the results of an efficiency audit.

The final standards in this action do not depend upon when the modification commences, as long as it commences after June 18, 2014. We are establishing emission standards for large modifications in this rule and deferring at this time the setting of standards for small modifications.

In this final action, the EPA is issuing final emission standards for affected steam generating units that implement larger modifications that are consistent with the proposed BSER determination for those units. The final standard for those sources that implement larger modifications is a unit-specific emission limitation consistent with each modified unit's best one-year historical performance (during the years from 2002 to the time of the modification), but does not include the additional two percent reduction that was proposed in the January 2014 proposal.

In this action, the EPA is not finalizing standards for those sources that conduct smaller modifications and is withdrawing the proposed standards for those sources. See Section XV below.

A more detailed discussion of the rationale for the BSER determination and final standards is provided in Section VI of this preamble.

3. BSER for Reconstructed Steam Generating Units

Consistent with our proposal, the EPA has determined that the BSER for reconstructed steam generating units is the most efficient demonstrated generating technology for these types of units (*i.e.,* meeting a standard of performance consistent with a reconstructed boiler using the most efficient steam conditions available, even if the boiler was not originally designed to do so). A more detailed discussion of the rationale for the BSER determination and the final standards is provided in Section VII of this preamble.

C. Final Standards of Performance

The EPA is issuing final standards of performance for newly constructed, modified, and reconstructed affected steam generating units based on the degree of emission reduction achievable by application of the best system of emission reduction for those categories, as described above. The final standards are presented below in Table 6.

TABLE 6—FINAL STANDARDS OF PERFORMANCE FOR NEW, MODIFIED, AND RECONSTRUCTED STEAM GENERATING UNITS

Source	Description	Final standard * lb CO_2/MWh-g
New Sources	All newly constructed steam generating EGUs	1,400.

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[182] Although co-firing with natural gas is not part of BSER, as noted above, it could be part of a compliance pathway for either SCPC or IGCC units. In this regard, a number of commenters addressed the issue of natural gas co-firing, indicating that there were circumstances where it could be part of BSER. See *e.g.* Comments of Exelon Corp. p. 12 (Docket entry: EPA–HQ–OAR–2013–0495–9406); Comments of the Sierra Club p. 108 Docket entry: EPA–HQ–OAR–2013–0495–9514). See *Northeast Md. Waste Disposal Authority* v. *EPA,* 358 F.3d 936, 952 (D.C. Cir. 2004); *Appalachian Power* v. *EPA,* 135 F.3d 791, 816 (D.C. Cir. 1998) (commenters understood a matter was under consideration when they addressed it in comments).

[183] Certain commenters maintained that the BSER determination does not comply with (purportedly) binding legal requirements created by regulations implementing the Information Quality Act. These comments are mistaken as a matter of both law and fact. The Information Quality Act does not create legal rights in third parties (see, *e.g. Mississippi Comm'n on Environmental Quality* v. *EPA,* no. 12–1309 at 84 (D.C. Cir. June 2, 2015)), and the OMB Guidelines are not binding rules but rather, as their title indicates, guidance to assist agencies. See *State of Mississippi,* 744 F.3d at 1347 (the Guidelines provide ''policy and procedural guidance'', are meant to be ''flexible'' and are to be implemented differently by different agencies accounting for circumstances). There are also significant factual omissions and mischaracterizations in these comments regarding peer review of the proposed standard and underlying record information. The complete response to these comments is in chapter 2 of the RTC. See also Section V.I.2.a and N below describing findings of the SAB panel that materials of the National Energy Technology Laboratory had been fully and adequately peer reviewed, and that the EPA findings related to sequestration of captured CO_2 reflected the best available science.

TABLE 6—FINAL STANDARDS OF PERFORMANCE FOR NEW, MODIFIED, AND RECONSTRUCTED STEAM GENERATING UNITS—Continued

Source	Description	Final standard * lb CO_2/MWh-g
Modified Sources	Sources that implement larger modifications—those resulting in an increase in hourly CO_2 emissions (lb CO_2/hr) of more than 10 percent.	Best annual performance (lb CO_2/MWh-g) during the time period from 2002 to the time of the modification.
Reconstructed Sources	Large **	1,800.
Reconstructed Sources	Small **	2,000.

* Standards are to be met over a 12-operating-month compliance period.
** Large units are those with heat input capacity of >2,000 mmBtu/hr; small units are those with heat input capacity of ≤2,000 mmBtu/hr.

For newly constructed and reconstructed steam generating units and for modified steam generating sources that result in larger hourly increases of CO_2 emissions, the EPA is finalizing standards in the form of a gross energy output-based CO_2 emission limit expressed in units of mass per useful energy output, specifically, in pounds of CO_2 per megawatt-hour (lb CO_2/MWh-g).[184] The standard of performance will apply to affected EGUs upon the effective date of the final action.

Compliance with the final standard will be demonstrated by summing the emissions (in pounds of CO_2) for all operating hours in the 12-operating-month compliance period and then dividing that value by the sum of the useful energy output (on a gross basis, *i.e.,* gross megawatt-hours) over the rolling 12-operating-month compliance period. The final rule requires rounding of emission rates with numerical values greater than or equal to 1,000 to three significant figures and rounding of rates with numerical values less than 1,000 to two significant figures.

For newly constructed steam generating units, we proposed two options for the compliance period. We proposed that a newly constructed source could choose to comply with a 12-operating-month standard or with a more stringent standard over an 84-operating-month compliance period, and we solicited comment on including an interim 12-operating-month standard (based on use of supercritical boiler technology, see 79 FR at 1448). We are not finalizing the proposed 84-operating-month compliance period option because the final standard of performance for newly constructed sources is less stringent than the proposed standard and because, as discussed in Section V below, we are identifying alternative compliance pathways for new steam generating EGUs. Specifically, we have concluded that there are unlikely to be significant issues with short-term variability during initial operation, in view of both the reduced numerical stringency of the standard, and the availability of compliance alternatives. The EPA notes that co-firing of natural gas can also serve as an interim means to reduce emissions if a new source operator believes additional time is needed to phase-in the operation of a CCS system. Therefore, the applicable final standards of performance for all newly constructed, modified, and reconstructed steam generating units must be met over a rolling 12-operating-month compliance period.

In the Clean Power Plan, which is a separate rulemaking under CAA section 111(d) published at the same time as the present rulemaking under CAA section 111(b), the EPA is promulgating emission guidelines for states to develop state plans regulating CO_2 emissions from existing fossil fuel-fired EGUs. Existing sources that are subject to state plans under CAA section 111(d) may undertake modifications or reconstructions and thereby become subject to the requirements under section 111(b) in the present rulemaking. In the section 111(d) Clean Power Plan rulemaking, the EPA discusses how undertaking a modification or reconstruction affects an existing source's section 111(d) requirements.

V. Rationale for Final Standards for Newly Constructed Fossil Fuel-Fired Electric Utility Steam Generating Units

In the discussion below, the EPA describes the rationale and justification of the BSER determination and the resulting final standards of performance for newly constructed steam generating units. We also explain why this determination is consistent with the constraints imposed by the EPAct05.

A. Factors Considered in Determining the BSER

In evaluating the final determination of the BSER for newly constructed steam generating units, the EPA considered the factors for the BSER described above, looked widely at all relevant information and considered all the data, information, and comments that were submitted during the public comment period. We re-examined and updated the information that was available to us and concluded, as described below, that the final standard of 1,400 lb CO_2/MWh-g is consistent with the degree of emission reduction achievable through the implementation of the BSER. This final standard of performance for newly constructed fossil fuel-fired steam generating units provides a clear and achievable path forward for the construction of new coal-fired generating sources that addresses GHG emissions.

B. Highly Efficient SCPC EGU Implementing Partial CCS as the BSER for Newly Constructed Steam Generating Units

In the sections that follow, we explain the technical configurations that may be used to implement BSER to meet the final standard, describe the operational flexibilities that partial CCS offers, and then provide the rationale for the final standard of performance. After that, we discuss, in greater detail, consideration of the criteria for the determination of the BSER. We describe why a highly efficient new SCPC EGU implementing partial CCS in the amount that results in an emission limitation of 1,400 lb CO_2/MWh-g best meets those criteria, including, among others, that such a system is technically feasible, provides meaningful emission reductions, can be implemented at a reasonable cost, does not pose non-air quality health and environmental concerns or impair energy reliability, and consequently is adequately demonstrated. We also explain why the emission standard of 1,400 lb CO_2/MWh-g is achievable, including under all circumstances

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[184] Note that the standards for sources that conduct larger modifications is a unit-specific numerical standard based on the unit's best one-year historical performance during the period from 2002 to the time of the modification. The unit-specific standard will also be in the form of a gross energy output-based CO_2 emission limit expressed in pounds of CO_2 per megawatt-hour (lb CO_2/MWh-g).

reasonably likely to occur when the system is properly designed and operated. We also discuss alternative compliance options that new source project developers can elect to use, instead of SCPC with partial CCS, to meet the final standard of performance.

C. Rationale for the Final Emission Standards

1. The Proposed Standards

In the January 2014 proposal, the EPA proposed an emission limitation of 1,100 lb CO_2/MWh-g, which a new highly efficient utility boiler burning bituminous coal could have met by capturing roughly 40 percent of its CO_2 emissions and a new highly efficient IGCC unit could have met by capturing and storing roughly 25 percent of its CO_2 emissions. The captured CO_2 would then be securely stored in sequestration repositories subject to either Class II or Class VI standards under the Underground Injection Control program. The EPA arrived at the proposed standard by examining the available CCS implementation configurations and concluding that the proposed standard at the corresponding levels of partial CCS best balanced the BSER criteria and resulted in an achievable emission level. The EPA also proposed to find that highly efficient new generation implementing ''full CCS'' (*i.e.,* more than 90 percent capture and storage) was not the BSER because the costs of that configuration—for both utility boilers and IGCC units—are projected to substantially exceed the projected costs of other non-NGCC dispatchable technologies that utilities and project developers are considering (*e.g.,* new nuclear and biomass). See generally 79 FR at 1477–78. Conversely, the EPA rejected highly efficient SCPC as the BSER because it would not result in meaningful emission reductions from any newly constructed PC unit. Id. at 1470. The EPA also declined to base the BSER on IGCC operating alone due to the same concern—lack of emission reductions from a new IGCC unit otherwise planned. Id.

2. Basis for the Final Standards

For this final action, the EPA reexamined the BSER options available at proposal. Those options are: (1) Highly efficient generation without CCS, (2) highly efficient generation implementing partial CCS, and (3) highly efficient generation implementing full CCS. Consistent with our determination in the January 2014 proposal, we remain convinced that highly efficient generation (*i.e.,* a new supercritical utility boiler or a new IGCC unit) without CCS does not represent the BSER because it does not achieve emission reductions beyond the sector's business as usual, when options that do achieve more emission reductions are available. 79 FR 1470; see also Section V.P below. We also do not find that a highly efficient new steam generating unit implementing full CCS is the BSER because, at this time, the costs are predicted to be significantly more than the costs for implementation of partial CCS and significantly more than the costs for competing non-NGCC base load, dispatchable technologies—primarily new nuclear generation—and are, therefore, potentially unreasonable. See Section V.P.

As with the proposal, the EPA has determined the final BSER and corresponding emission limitation by appropriately balancing the BSER criteria and determining that the emission limitation is achievable. The final standard of performance of 1,400 lb CO_2/MWh-g is less stringent than at proposal and reflects changes that are responsive to comments received on, and the EPA's further evaluation of, the costs to implement partial CCS. The EPA has determined that a newly constructed highly efficient supercritical utility boiler burning bituminous coal can meet this final emission limitation by capturing 16 percent of the CO_2 produced from the facility (or 23 percent if burning subbituminous or dried lignite), which would be either stored in on-site or off-site geologic sequestration repositories subject to control under either the Class VI (for geologic sequestration) or Class II (for Enhanced Oil Recovery) standards under the UIC program. This BSER is technically feasible, as shown by the fact that post-combustion CCS technology—both the capture and storage components—is demonstrated in full-scale operation within the electricity generating industry. There are also numerous operating results from smaller-scale projects that are reasonably predictive of operation at full-scale. It is available at reasonable cost, does not have collateral adverse non-air quality health or environmental impacts, and does not have adverse energy implications.

The proposed BSER was a highly efficient newly constructed steam generating EGU implementing partial CCS to an emission standard of 1,100 lb CO_2/MWh-g. The final BSER is a highly efficient SCPC EGU implementing partial CCS to achieve an emission standard of 1,400 lb CO_2/MWh-g. In both cases, the EPA specified that the BSER includes a ''highly efficient'' new EGU implementing partial CCS. This assumes that a new project developer will construct the most efficient generating technology available—*i.e.,* a supercritical or ultra-supercritical utility boiler—that will inherently generate lower volumes of uncontrolled CO_2 per MWh. See Section V.J below. A well performing and highly efficient new SCPC EGU will need to implement lower levels of partial CCS in order to meet the final standard of 1,400 lb CO_2/MWh-g than a less efficient new steam generating EGU. The construction of highly efficient steam generating EGUs—as opposed to less efficient units such as a subcritical utility boiler—will result in lower overall costs from decreased fuel consumption and the need for lower levels of required partial CCS to meet the final standard.

3. Consideration of Projects Receiving Funding Under the EPAct05

As noted in Section III.H.3.g above, the EPA's determination of the BSER here includes review of recently constructed facilities and those planned or under construction to evaluate the control technologies being used and considered. Some of the projects discussed in the January 2014 proposal, and discussed here in this preamble, received or are receiving financial assistance under the EPAct05 (P.L. 109–58). This assistance may include financial assistance from the Department of Energy (DOE), as well as receipt of the federal tax credit for investment in clean coal technology under IRC Section 48A.

As noted above, the EPA interprets these provisions as allowing consideration of EPAct05 facilities provided that such information is not the sole basis for the BSER determination, and particularly so in circumstances like those here, where the information is corroborative but the essential information justifying the determinations comes from facilities and other sources of information with no nexus with EPAct05 assistance. In the discussion below, the EPA explains its reliance on other information in making the BSER determination for new fossil fuel-fired steam generating units. The EPA notes that information from facilities that did not receive any DOE assistance, and did not receive the federal tax credit, is sufficient by itself to support its BSER determination.

D. Post-Combustion Carbon Capture

In this section, we describe a variety of facts that support our conclusion that the technical feasibility of post-combustion carbon capture is adequately demonstrated. First, we describe the technology of post-combustion capture. We then describe EGUs that have previously utilized or are currently utilizing post-combustion carbon capture technology. This discussion is complemented by later sections that explain and justify our conclusions that the technical feasibility of other aspects of partial CCS are adequately demonstrated—namely, the transportation and carbon storage (see Sections V.M. and N). Further, the conclusions of this section are reinforced by the discussion in Section V.F. below, in which we identify commercial vendors that offer carbon capture technology and offer performance guarantees, and discuss industry and technology developers' public pronouncements of their confidence in the feasibility and availability of CCS technologies.

1. Post-Combustion Carbon Capture—How it Works

Post-combustion capture processes remove CO_2 from the exhaust gas of a combustion system—such as a utility boiler. It is referred to as ''post-combustion capture'' because the CO_2 is the product of the combustion of the primary fuel and the capture takes place after the combustion of that fuel. The exhaust gases from most combustion processes are at atmospheric pressure and are moved through the flue gas system by fans. The concentration of CO_2 in most combustion flue gas streams is somewhat dilute.[185] Most post-combustion capture systems utilize liquid solvents[186] that separate the CO_2 from the flue gas in CO_2 scrubber systems. Because the flue gas is at atmospheric pressure and is somewhat dilute, the solvents used for post-combustion capture are ones that separate the CO_2 using chemical absorption (or chemisorption). Amine-based solvents[187] are the most commonly used in post-combustion capture systems. In a chemisorption-based separation process, the flue gas is processed through the CO_2 scrubber and the CO_2 is absorbed by the liquid solvent and then released by heating to form a high purity CO_2 stream. This heating step is referred to as ''solvent regeneration'' and is responsible for much of the ''energy penalty'' of the capture system. Steam from the boiler (or potentially from another external source) that would otherwise be used to generate electricity is instead used in the solvent regeneration process. The development of advanced solvents—those that are chemically stable, have high CO_2 absorption capacities, and have low regeneration energy requirements—is an active area of research. Many post-combustion solvents will also selectively remove other acidic gases such as SO_2 and hydrochloric acid (HCl), which can result in degradation of the solvent. For that reason, the CO_2 scrubber systems are normally installed downstream of other pollutant control devices (*e.g.,* particulate matter and flue gas desulfurization controls) and in some cases, the acidic gases will need to be scrubbed to very low levels prior to the flue gas entering the CO_2 capture system. See also RIA chapter 5 (quantifying SO_2 reductions resulting from this scrubbing process).

Additional information on post-combustion carbon capture—including process diagrams—can be found in a summary technical support document.[188]

2. Post-Combustion Carbon Capture Projects That Have Not Received DOE Assistance Through the EPAct05 or Tax Credits Under IRC Section 48A

a. Boundary Dam Unit #3

SaskPower's Boundary Dam CCS Project in Estevan, a city in Saskatchewan, Canada, is the world's first commercial-scale fully integrated post-combustion CCS project at a coal-fired power plant. The project fully integrates the rebuilt 110 MW coal-fired Unit #3 with a CO_2 capture system using Shell Cansolv amine-based solvent to capture 90 percent of its CO_2 emissions. The facility, which utilizes local Saskatchewan lignite, began operations in October 2014 and accounts of the system's performance describe it as working even ''better than expected.''[189] [190] The plant started by capturing roughly 75 percent of CO_2 from the plant emissions and its operators plan to increase the capture percentage as they optimize the equipment to reach full capacity. Initial indications are that the facility is producing more power than predicted and that the energy penalty (parasitic load—the energy needed to regenerate the CO_2 capture solvent) is much lower than initially predicted.[191] Water use at the facility is consistent with levels that were predicted.[192] The total project costs—for the power plant and the carbon capture plant—was $1.467B (CAD).[193] The CO_2 from the capture system is more than 99.999 percent pure with only trace levels of N_2 in the product stream.[194] This purity is food-grade quality CO_2 and is a clear indication that the system is working well. The captured CO_2 is transported by pipeline to nearby oil fields in southern Saskatchewan where it is being used for EOR operations. Any captured CO_2 that is not used for EOR operations will be stored in nearby deep brine-filled sandstone formations. Thus, the Boundary Dam Unit #3 project is demonstrating CO_2 post-combustion capture, CO_2 compression and transport, and CO_2 injection for both EOR and geologic storage. The CCS system is fully integrated with the electricity production of the plant.

Some commenters noted that, at 110 MW, the Boundary Dam Unit #3 is a relatively small coal-fired utility boiler and thus, in the commenters' view, does not demonstrate that such a system could be utilized at a much larger utility coal-fired boiler. However, there is nothing to indicate that the post-combustion system used at Boundary Dam could not be scaled-up for use at a larger utility boiler. In fact, the carbon capture system at Boundary Dam #3 is designed and constructed to implement ''full CCS''—that is to capture more than 90 percent of the CO_2 produced from the subcritical unit. A similarly-sized capture system—with no need for further scale-up—could be used to treat a slip-stream of a much larger

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[185] The typical concentration of CO_2 in the flue gas of a coal-fired utility boiler is roughly around 15 volume percent.

[186] A *solvent* is a substance (usually a liquid) that dissolves a *solute* (a chemically different liquid, solid or gas), resulting in a solution.

[187] Amines are derivatives of ammonia (NH_3) where one or more hydrogen atoms have been replaced by hydrocarbon groups.

[188] Technical Support Document—''Literature Survey of Carbon Capture Technology'', available in the rulemaking docket (Docket ID: EPA–HQ–OAR–2013–0495).

[189] ''[W]e are achieving better than expected'' operation out of the plant, SaskPower's Mike Marsh said April 8, 2015 in Washington, DC, summarizing the status of the first-of-a-kind plant in Saskatchewan, Canada, known as Boundary Dam Unit 3. Marsh spoke at a meeting of the National Coal Council, which advises the Energy Department on coal-related topics. From ''Bolstering EPA's NSPS, Canadian CCS Plant Working 'Better Than Expected' '', Climate Daily News, Inside EPA/climate (April 08, 2015); *www.insideepa.com* (subscription required).

[190] ''CCS performance data exceeding expectations at world-first Boundary Dam Power Station Unit #3'', *http://www.saskpowerccs.com/newsandmedia/latest-news/ccs-performance-data-exceeding-expectations/*.

[191] Correspondence between Mike Monea (SaskPower) and Nick Hutson (EPA), February 20, 2015.

[192] 30 percent of the water used for cooling comes from the recycled or reclaimed water from the process itself; namely, water in the coal is reclaimed.

[193] About $1.2B USD; roughly $700M (USD) for the carbon capture system, which was on budget.

[194] ''Boundary Dam—The Future is Here'', plenary presentation by Mike Monea at the 12th International Conference on Greenhouse Gas Technologies (GHGT–12), Austin, TX (October 2014).

supercritical utility boiler (a new unit of approximately 500 to 600 MW) in order to meet the final standard of performance of 1,400 lb CO_2/MWh-g, which would only require partial CCS on the order of approximately 16 to 23 percent (depending on the coal used).

A ''slip-stream'' is a portion of the flue gas stream that can be treated separately from the bulk exhaust gas. It is not an uncommon configuration for the flue gas from a coal-fired boiler to be separated into two or more streams and treated separately in different control equipment before being recombined to exit from a common stack.[195] A slip-stream configuration is often used to treat a smaller portion of the bulk flue gas stream as a way of testing or demonstrating a control device or measurement technology. For implementation of post-combustion partial carbon capture, a portion of the bulk flue gas stream would be treated separately to capture approximately 90 percent of the CO_2 from that smaller slip-stream of the flue gas. For example, in order to capture 20 percent of the CO_2 produced by a coal-fired utility boiler, an operator would treat approximately 25 percent of the bulk flue gas stream (rather than treating the entire stream). Approximately 90 percent of the CO_2 would be captured from the slip-stream gas, resulting in an overall capture of about 20 percent.

In its study on the cost and performance of a range of carbon capture rates, the DOE/NETL determined that the slip-stream approach was the most economical for carbon capture of less than 90 percent of the total CO_2.[196] The advantage of the slip-stream approach is that the capture system will be sized to treat a lower volume of flue gas flow, which reduces the size of the CO_2 absorption columns, induced draft fans, and other equipment, leading to lower capital and operating costs.

The carbon capture system at Boundary Dam does not utilize the slip-stream configuration because it was designed to achieve more than 90 percent capture rates from the 110 MW facility. However, the same carbon capture equipment could be used to treat approximately 50 percent of the flue gas from a 220 MW facility—or 20 percent of the flue gas from a 550 MW facility. Thus, the equipment that is currently working very well (in fact, ''better than expected'') at the Boundary Dam plant can be utilized for partial carbon capture at a much larger coal-fired unit without the need for further scale-up.

The experience at Boundary Dam is directly transferrable to other types of post-combustion sources, including those using different boiler types and those burning different coal types. There is nothing to suggest that the Shell CanSolv process would not work with other coal types and indeed, the latest NETL cost estimates assume that the capture technology would be used in a new unit using bituminous coal.[197] The EPA is unaware of any reasons why the Boundary Dam technology would not be transferrable to another utility boiler at a different location at a different elevation or climate because the control technology is not climate or elevation-dependent.

Commenters also noted that the Boundary Dam Unit #3 project received financial assistance from both the Canadian federal government and from the Saskatchewan provincial government. But the availability of—or the lack of—external financial assistance does not affect the technical feasibility of the technology. Commenters further characterized Boundary Dam as a ''demonstration project''. These descriptors are beside the point. Regardless of what the project is called or how it was financed, the project clearly shows the technical feasibility of full-scale, fully integrated implementation of available post-combustion CCS technology, which in this case also appears to be commercially viable.

The EPA notes that, although there is ample additional information corroborating that post-combustion CCS is technically feasible, which we describe below, the performance at Boundary Dam Unit #3 alone would be sufficient to support that conclusion. *Essex Chemical Corp.,* 486 F. 2d at 436 (test results from single facility demonstrates achievability of standard of performance). As mentioned above, the post-combustion capture technology used at Boundary Dam is transferrable to all other types of utility boilers.

b. AES Warrior Run and Shady Point

AES's coal-fired Warrior Run (Cumberland, MD) and Shady Point (Panama, OK) plants are both circulating fluidized bed (CFB) coal-fired power plants with carbon capture amine scrubbers developed by ABB/Lummus. The scrubbers were designed to process a slip-stream of each plant's flue gas. At the 180 MW Warrior Run Plant, a plant that burns bituminous coal, approximately 10 percent of the plant's CO_2 emissions (about 110,000 metric tons of CO_2 per year) has been captured since 2000 and sold to the food and beverage industry. At the 320 MW Shady Point Plant, a plant that burns a blend of bituminous and subbituminous coals, CO_2 from an approximate 5 percent slip-stream (about 66,000 metric tons of CO_2 per year) has been captured since 2001. The captured CO_2 from the Shady Point Plant is also sold for use in the food processing industry.[198] While these projects do not demonstrate the CO_2 storage component of CCS, they clearly demonstrate the technical viability of partial CO_2 capture. The capture of CO_2 from a slip-stream of the bulk flue gas, as described earlier, is the most economical method for capturing less than 90 percent of the CO_2. The amounts of partial capture that these sources have demonstrated—up to 10 percent—is reasonably similar to the level, at 16 to 23 percent, that the EPA predicts would be needed by a new highly efficient steam utility boiler to meet the final standard of performance. These facilities, which have been operating for multiple years, clearly show the technical feasibility of post-combustion carbon capture.

c. Searles Valley Minerals

Since 1978, the Searles Valley Minerals soda ash plant in Trona, CA has used post-combustion amine scrubbing to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of a coal-fired power plant that generates steam and power for on-site use. The captured CO_2 is used for the carbonation of brine in the process of producing soda ash.[199] Again, while the captured CO_2 is not

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[195] See Figure 1A from *Atmospheric Environment,* 43, 3974 (2009), for an example of this type of configuration.

[196] ''Cost and Performance of PC and IGCC for a Range of Carbon Capture'', Rev 1 (2013), DOE/NETL–2011/1498 p. 2 (''A literature search was conducted to verify that <90 percent CO_2 capture is most economical using a 'slip-stream' (or bypass) approach. Indeed, the slip-stream approach is more cost-effective for <90 percent CO_2 capture than removing reduced CO_2 fractions from the entire flue gas stream, according to multiple peer-reviewed studies.'' See also id. at 19, 21, 77, and 478 (documenting further that treating a slip-stream is the most economical approach).

[197] In fact, in ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3'', DOE/NETL–2015/1723 (July 2015), Exh.2–3 the Shell Cansolv process is used as the capture process for a new SCPC unit using bituminous coal rather than the subcritical PC unit at Boundary Dam that uses Canadian lignite. The study evidently assumes that the CanSolv process can be used effectively for bituminous coal since this type of coal is assumed for cost estimation purposes.

[198] Dooley, J. J., et al. (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009''. U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[199] IEA (2009), World Energy Outlook 2009, OECD/IEA, Paris.

sequestered, this project clearly demonstrates the technical feasibility of the amine scrubbing system for CO_2 capture from a coal-fired power plant.[200] The fact that this system is an industrial coal-fired power plant rather than a utility coal-fired power plant is irrelevant as they both serve a similar purpose—the production of electricity.

Each of these processes indicate a willingness of industry to utilize available post-combustion technology for capture of CO_2 for commercial purposes. Not one of the CO_2 capture systems at Warrior Run, Shady Point, or Searles Valley was installed for regulatory purposes or as government-funded demonstration projects. They were installed to capture CO_2 for commercial use. The fact that the captured CO_2 was utilized rather than being stored is of no consequence in the consideration of the technical feasibility of post-combustion CO_2 capture technology. These commercial operations have helped to improve the performance of scrubbing systems that are available today. For example, the heat duty (*i.e.,* the energy needed to remove the CO_2) has been reduced by about 5 times from the amine process originally used at the Searles Valley facility. The amine scrubbing process used at Boundary Dam is equally efficient, and the amine scrubbing system to be used at the Petra Nova WA Parish project (Thompsons, TX) is projected to be as well.[201]

3. Post-Combustion Carbon Capture Projects That Received DOE Assistance Through the EPAct05, but Did Not Receive Tax Credits Under IRC Section 48A

The EPA considers the experiences from the CCS projects described above, coupled with evidence that the design of CCS is well accepted (also described above) and the strong support that CCS has received from vendors and others (described below) to adequately demonstrate that post-combustion partial CCS is technically feasible. The EPA finds that additional projects, described next, provide more support for that conclusion. These projects received funding under EPAct05 from the Department of Energy, but that does not disqualify them from being considered. See Section III.H.3 above.

a. Petra Nova WA Parish Project

Petra Nova, a joint venture between NRG Energy Inc. and JX Nippon Oil & Gas Exploration, is constructing a commercial-scale post-combustion carbon capture project at Unit #8 of NRG's WA Parish generating station southwest of Houston, Texas. The project is designed to utilize partial CCS by capturing approximately 90 percent of the CO_2 from a 240 MW slip-stream of the 610 MW WA Parish facility. The project is expected to be operational in 2016 and thus does not yet directly demonstrate the technical feasibility or performance of the MHI amine scrubbing system. However, this project is a clear indication that the developers have confidence in the technical feasibility of the post-combustion carbon capture system.

The project was originally envisioned as a 60 MW slip-stream demonstration and received DOE Clean Coal Power Initiative (CCPI) funding (as provided in EPAct05) on that basis. The developers later expanded the project to the larger 240 MW slip-stream because of the need to capture greater volumes of CO_2 for EOR operations. No additional DOE or other federal funding was obtained for the expansion from a 60 MW slip-stream to a 240 MW slip-stream.[202]

At 240 MW, the Petra Nova project will be the largest post-combustion carbon capture system installed on an existing coal-fueled power plant. The project will use for EOR or will sequester 1.6 million tons of captured CO_2 each year. The project is expected to be operational in 2016.

In 2014 project materials,[203] the project developer NRG recognized the importance of CCS technology by noting:

> The technology has the potential to enhance the long-term viability and sustainability of coal-fueled power plants across the U.S. and around the world. . . . Post-combustion carbon capture is essential so that we can use coal to sustain our energy ecosystem while we begin reducing our carbon footprint.

According to NRG, the Petra Nova Carbon Capture Project will utilize ''a proven carbon capture process,'' jointly developed by Mitsubishi Heavy Industries, Ltd. (MHI) and the Kansai Electric Power Co., that uses a high-performance solvent for CO_2 absorption and desorption.[204] In using the MHI high-performance solvent, the Petra Nova project will benefit from pilot-scale testing of this solvent at Alabama Power's Plant Barry and at other installations. WA Parish Unit #8 came on-line in 1982 and is thus an existing source that will not be subject to final standards of performance issued in this action. However, because it will be capturing roughly 35 percent of the CO_2 generated by the facility, its emissions will be below the final new source emission limitation of 1,400 lb CO_2/MWh-g.[205]

The captured CO_2 from the WA Parish CO_2 Capture Project will be used in EOR operations at mature oil fields in the Gulf Coast region. Using EOR at Hilcorp's West Ranch Oil Field, the production is expected to be boosted from around 500 barrels per day to approximately 15,000 barrels per day. Thus the project will utilize all aspects of CCS by capturing CO_2 at the large coal-fired power plant, compressing the CO_2, transporting it by pipeline to the EOR operations, and injecting it for EOR and eventual geologic storage.

The carbon capture system at WA Parish will utilize a slip-stream configuration. However, as noted, the system is designed to capture roughly 35 percent of the CO_2 from WA Parish Unit #8 (90 percent of the CO_2 from the 240 MW slip-stream from the 610 MW unit). A carbon capture system of the same size as that used at WA Parish could be used to treat a 240 MW slip-stream from a 1,000 MW unit in order to meet the final standard of performance of 1,400 lb CO_2/MWh-g.

Again, the experience at the WA Parish Unit #8 project will be directly transferable to post-combustion capture at a new utility boiler, even though WA Parish Unit #8 is an existing source that has been in operation for over 30 years. In fact, retrofit of such technology at an existing unit can be more challenging than incorporating the technology into the design of a new facility. The

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[200] Moreover, the final rule allows alternative means of storage of captured CO_2 based on a case-by-case demonstration of efficacy. See Section V.M.4 below.

[201] The heat duty for the amine scrubbing process used at Searles Valley in the mid-70's was about 12 MJ/mt CO_2 removed as compared to a heat duty of about 2.5 MJ/mt CO_2 removed for the amine processes used at Boundary Dam and to be used at WA Parish. ''From Lubbock, TX to Thompsons, TX—Amine Scrubbing for Commercial CO_2 Capture from Power Plants'', plenary address by Prof. Gary Rochelle at the 12th International Conference on Greenhouse Gas Technology (GHGT–12), Austin, TX (October 2014).

[202] Thus, even if the project received DOE assistance for the initial 60 MW design, the expansion of the project from 60 MW to 240 MW should not be considered a DOE-assisted project. In any case, as described above, even without consideration of this facility at all, other information adequately demonstrates the technical feasibility of post-combustion CCS.

[203] WA Parish CO_2 Capture Project Fact Sheet; available at *www.nrg.com/documents/business/pla-2014-petranova-waparish-factsheet.pdf* (2014).

[204] The WA Parish project (described earlier) will utilize the KM–CDR Process®, which was jointly developed by MHI and the Kansai Electric Power Co., Inc. and uses the proprietary KS–1™ high-performance solvent for the CO_2 absorption and desorption.

[205] Using emissions data reported to the Acid Rain Program, the EPA estimates that the CO_2 emissions from the WA Parish Unit #8 will be 1,250–1,300 lb CO_2/MWh-g during operations with the post-combustion capture system.

experience will be directly transferrable to other types of post-combustion sources including those using different boiler types and those burning different coals. The amine scrubbing and associated systems are not boiler type- or coal-specific. The EPA is unaware of any reasons that the technology utilized at the WA Parish plant would not be transferrable to another utility boiler at a different location at a different elevation or climate, given that the technology is not dependent on either climate or topography.

b. AEP/Alstom Mountaineer Project

In September 2009, AEP began a pilot-scale CCS demonstration at its Mountaineer Plant in New Haven, WV. The Mountaineer Plant is a very large (1,300 MW) coal-fired unit that was retrofitted with Alstom's patented chilled ammonia CO_2 capture technology on a 20 MWe slip-stream of the plant's exhaust flue gas. In May 2011, Alstom Power announced the successful operation of the chilled ammonia CCS validation project. The demonstration achieved capture rates from 75 percent (design value) to as high as 90 percent, and produced CO_2 at a purity of greater than 99 percent, with energy penalties within a few percent of predictions. The facility reported robust steady-state operation during all modes of power plant operation, including load changes, and saw an availability of the CCS system of greater than 90 percent.[206]

AEP, with assistance from the DOE, had planned to expand the slip-stream demonstration to a commercial scale, fully integrated demonstration at the Mountaineer facility. The commercial-scale system was designed to capture at least 90 percent of the CO_2 from 235 MW of the plant's 1,300 MW total capacity. Plans were for the project to be completed in four phases, with the system to begin commercial operation in 2015. However, in July 2011, AEP announced that it would terminate its cooperative agreement with the DOE and place its plans to advance CO_2 capture and storage technology to commercial scale on hold. AEP cited the uncertain status of U.S. climate policy as a contributor to its decision, but did not express doubts about the feasibility of the technology. See Section V.L below.

AEP also prepared a Front End Engineering & Design (FEED) Report,[207] explaining in detail how its pilot-scale work could be scaled up to successful full-scale operation, and to accommodate the operating needs of a full-scale EGU, including reliable generating capacity capable of cycling up and down to accommodate consumer demand. Recommended design changes to accomplish the desired scaling included detailed flue gas specifications, ranges for temperature, moisture and SO_2 content; careful scrutiny of makeup water composition and temperature; quality and quantity of available steam to accommodate heat cycle based on unit load changes; and detailed scrutiny of material and energy balances.[208] See Section V.G.3 below, addressing in more detail the record support for how CCS technology can be scaled up to commercial size in both pre- and post-combustion applications.

c. Southern Company/MHI Plant Barry

In June 2011, Southern Company and Mitsubishi Heavy Industries (MHI) launched operations at a 25 MW coal-fired carbon capture facility at Alabama Power's Plant Barry. The facility, which completed the initial demonstration phase, captured approximately 165,000 metric tons of CO_2 annually at a CO_2 capture rate of over 90 percent. The facility employed the KM CDR Process, which uses a proprietary high performing solvent[209] for CO_2 absorption and desorption that was jointly developed by MHI and Japanese utility Kansai Electric Power Co. The captured CO_2 has been transported via pipeline approximately 12 miles to the Citronelle oil field where it is injected into the Paluxy formation, a saline reservoir, for storage.[210]

Project participants have reported that ''[t]he plant performance was stable at the full load condition with CO_2 capture rate of 500 TPD at 90 percent CO_2 removal and lower steam consumption than conventional capture processes.''[211]

E. Pre-Combustion Carbon Capture

As described earlier, the EPA does not find that IGCC technology—either alone or implementing partial CCS—is part of the BSER for newly constructed steam generating EGUs. However, as noted, there may be specific circumstances and business plans—such as co-production of chemicals or fertilizers, or capture of CO_2 for use in EOR operations—that encourage greater CO_2 emission reductions than are required by this standard. In this section, we describe and justify our conclusion that the technical feasibility of pre-combustion carbon capture is adequately demonstrated, indicating that this could be a viable alternative compliance pathway. First, we explain the technology of pre-combustion capture. We then describe EGUs that have previously utilized or are currently utilizing pre-combustion carbon capture technology. This discussion is complemented by other sections that conclude the technical feasibility of other aspects of partial CCS are adequately demonstrated—namely, post-combustion carbon capture (Section V.D) and sequestration (Sections V.M and V.N). Further, this section's conclusions are reinforced by Section V.F, in which we identify commercial vendors that offer CCS performance guarantees as well as developers that have publicly stated their confidence in CCS technologies.

1. Pre-Combustion Carbon Capture—How It Works

Pre-combustion capture systems are typically used with IGCC processes. In a gasification system, the fuel (usually coal or petroleum coke) is heated with water and oxygen in an oxygen-lean environment. The coal (carbon), water and oxygen react to form primarily a mixture of hydrogen (H_2) and carbon monoxide (CO) known as synthesis gas or syngas according to the following high temperature reaction:

$$3C + H_2O + O_2 \rightarrow H_2 + 3CO$$

In an IGCC system, the resulting syngas, after removal of the impurities, can be combusted using a conventional combustion turbine in a combined cycle configuration (*i.e.,* a combustion turbine combined with a HRSG and steam turbine). The gasification process also typically produces some amount of CO_2[212] as a by-product along with other

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[206] *http://www.alstom.com/press-centre/2011/5/alstom-announces-sucessful-results-of-mountaineer-carbon-capture-and-sequestration-ccs-project/.*

[207] ''CCS front end engineering & design report: American Electric Power Mountaineer CCS II Project. Phase 1'', pp 10–11; available at: *http://www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report.*

[208] Id. at 11. The EPA does not view this information as being affected by the constraints in EPAct05. The information does not relate to use of technology, level of emission reduction by reason of use of technology, achievement of emission reduction by demonstration of technology, or demonstration of a level of performance. The FEED study rather explains engineering challenges which would remain at full scale and how those challenges can be addressed.

[209] This is the same carbon capture system that is being utilized at the Petra Nova project at the NRG WA Parish plant.

[210] Ivie, M.A. et al.; ''Project Status and Research Plans of 500 TPD CO_2 Capture and Sequestration Demonstration at Alabama Power's Plant Barry'', *Energy Procedia* 37, 6335 (2013).

[211] Id.

[212] The amount of CO_2 in syngas depends upon the specific gasifier technology used, the operating conditions, and the fuel used; but is typically less

gases (*e.g.,* H_2S) and inorganic materials originating from the coal (*e.g.,* minerals, ash). The amount of CO_2 in the syngas can be increased by ''shifting'' the composition via the catalytic water-gas shift (WGS) reaction. This process involves the catalytic reaction of steam (''water'') with CO (''gas'') to form H_2 and CO_2 according to the following catalytic reaction:

$CO + H_2O \rightarrow CO_2 + H_2$

An emission standard that requires partial capture of CO_2 from the syngas could be met by adjusting the level of CO_2 in the syngas stream by controlling the level of syngas ''shift'' prior to treatment in the pre-combustion acid gas treatment system. If a high level of CO_2 capture is required, then multi-stage WGS reactors will be needed and an advanced hydrogen turbine will likely be needed to combust the resulting hydrogen-rich syngas.

Most syngas streams are at higher pressure and can contain higher concentrations of CO_2 (especially if shifted to enrich the concentration). As such, the pre-combustion capture systems can utilize physical absorption (physisorption) solvents rather than the chemical absorptions solvents described earlier. Physical absorption has the benefit of relying on weak intermolecular interactions and, as a result, the absorbed CO_2 can often be released (desorbed) by reducing the pressure rather than by adding heat. Pre-combustion capture systems have been used widely in industrial processes such as natural gas processing.

Additional information on pre-combustion carbon capture can be found in a summary technical support document.[213]

2. Pre-Combustion Carbon Capture Projects That Have Not Received DOE Assistance Through EPAct05 or Tax Credits Under IRC Section 48A

a. Dakota Gasification Great Plains Synfuels Plant

Each day, the Dakota Gasification Great Plains Synfuels Plant uses approximately 18,000 tons of North Dakota lignite in a coal gasification process that produces syngas (a mixture of CO, CO_2, and H_2), which is then converted to methane gas (synthetic natural gas) using a methanation process. Each day, the process produces an average of 145 million cubic feet of synthetic natural gas that is ultimately transported for use in home heating and electricity generation.[214]

Capture of CO_2 from the facility began in 2000. The Synfuels Plant, using a pre-combustion Rectisol® process, captures about 3 million tons of CO_2 per year—more CO_2 from coal conversion than any facility in the world, and is a participant in the world's largest carbon sequestration project. On average about 8,000 metric tons per day of captured CO_2 from the facility is sent through a 205-mile pipeline to oil fields in Saskatchewan, Canada, where it is used for EOR operations that result in permanent CO_2 geologic storage. The geologic sequestration of CO_2 in the oil reservoir is monitored by the International Energy Agency (IEA) Weyburn CO_2 Monitoring and Storage Project.

Several commenters to the January 2014 proposal argued that the Great Plains Synfuels facility is not an EGU, that it operates as a chemical plant, and that its experience is not translatable to an IGCC using pre-combustion carbon capture technology. The commenters noted that the Dakota facility can be operated nearly continuously without the need to adjust operations to meet cyclic electricity generation demands. In the January 2014 proposal, the EPA had noted that, while the facility is not an EGU, it has significant similarities to an IGCC and the implementation of the pre-combustion capture technology would be similar enough for comparison. See 79 FR at 1435–36 and n. 11. We continue to hold this view.

As explained above, in an IGCC gasification system, coal (or petroleum coke) is gasified to produce a synthesis gas comprised of primarily CO, H_2, and some amount of CO_2 (depending on the gasifier and the specific operating conditions). A water-gas-shift reaction using water (H_2O, steam) is then used to shift the syngas to CO_2 and H_2. The more the syngas is ''shifted,'' the more enriched it becomes in H_2. In an IGCC, power can be generated by directly combusting the un-shifted syngas in a conventional combustion turbine. If the syngas is shifted such that the resulting syngas is highly enriched in H_2, then a special, advanced hydrogen turbine is needed. If CO_2 is to be captured, then the syngas would need to be shifted either fully or partially, depending upon the level of capture required.[215]

The Dakota Gasification process bears essential similarities to the just-described IGCC gasification system. As with the IGCC gasification system, the Dakota Gasification facility gasifies coal (lignite) to produce a syngas which is then shifted to increase the concentration of CO_2 and to produce the desired ratio of CO and H_2. As with the IGCC gasification system, the CO_2 is then removed in a pre-combustion capture system, and the syngas that results is made further use of. For present purposes, only the manner in which the syngas is used distinguishes the IGCC gasification system from the Dakota Gasification facility. In the IGCC process, the syngas is combusted. In the Dakota Gasification facility, the syngas is processed through a catalytic methanation process where the CO and H_2 react to produce CH_4 (methane, synthetic natural gas) and water. Importantly, the CO_2 capture system that is used in the Dakota Gasification facility can readily be used in an IGCC EGU. There is no indication that the RECTISOL® process (or other similar physical gas removal systems) is not feasible for an IGCC EGU. In confirmation, according to product literature, RECTISOL®, which was independently developed by Linde and Lurgi, is frequently used to purify shifted, partially shifted or un-shifted gas from the gasification of coal, lignite, and residual oil.[216]

b. International Projects

There are some international projects that are in various stages of development that indicate confidence by developers in the technical feasibility of pre-combustion carbon capture. Summit Carbon Capture, LLC is developing the Caledonia Clean Energy Project, a proposed 570-megawatt IGCC plant with 90 percent CO_2 capture that would be built in Scotland, U.K. Captured CO_2 from the plant will be transported via on-shore and sub-sea pipeline for sequestration in a saline formation in the North Sea. The U.K. Department of Energy & Climate Change (DECC) recently announced funding to allow for feasibility studies for this plant.[217] Commercial operation is expected in 2017.[218]

The China Huaneng Group—with multiple collaborators, including Peabody Energy, the world's largest private sector coal company—is building the 400 MW GreenGen IGCC

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than 20 volume percent (*http://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/syngas-composition*).

[213] Technical Support Document—''Literature Survey of Carbon Capture Technology'', available in the rulemaking docket (Docket ID: EPA–HQ–OAR–2013–0495).

[214] *http://www.dakotagas.com/Gasification/.*

[215] ''Cost and Performance of PC and IGCC for a Range of Carbon Capture'', Rev 1 (2013), DOE/NETL–2011/1498.

[216] *www.linde-engineering.com/en/process_plants/hydrogen_and_synthesis_gas_plants/gas_processing/rectisol_wash/index.html.*

[217] *http://www.downstreambusiness.com/item/Summit-Power-Wins-Funding-Studies-Proposed-IGCC-CCS-Project_140878.*

[218] *http://www.summitpower.com/projects/carbon-capture/.*

facility in Tianjin City, China. The goal is to complete the power plant before 2020. Over 80 percent of the CO_2 will be separated using pre-combustion capture technology. The captured CO_2 will be used for EOR operations.[219]

Vattenfall and Nuon's pilot project in Bugennum, The Netherlands involves carbon capture from coal- and biomass-fired IGCC plants. It has operated since 2011.[220]

Approximately 100 tons of CO_2 per day are captured from a coal- and petcoke-fired IGCC plant in Puertollano, Spain. The facility began operating in 2010.[221]

Emirates Steel Industries is expected to capture approximately 0.8Mt of CO_2 per year from a steel-production facility in the United Arab Emirates. Full-scale operations are scheduled to begin by 2016.[222]

The Uthmaniyah CO_2 EOR Demonstration Project in Saudi Arabia will capture 0.8 Mt of CO_2 from a natural gas processing plant over three years. It is expected to begin operating in 2015.[223]

The experience of the Dakota Gasification facility, coupled with the descriptions of the technology in the literature, the statements from vendors, and the experience of facilities internationally, are sufficient to support our determination that the technical feasibility of CCS for an IGCC facility is adequately demonstrated. The experience of additional facilities, described next, provides additional support.

3. Pre-Combustion Carbon Capture Projects That Have Received DOE Assistance Through EPAct05, but Did Not Receive Tax Credits Under IRC Section 48A

a. Coffeyville Fertilizer

Coffeyville Resources Nitrogen Fertilizers, LLC, owns and operates a nitrogen fertilizer facility in Coffeyville, Kansas. The plant began operation in 2000 and is the only one in North America using a petroleum coke-based fertilizer production process. The petroleum coke is generated at an oil refinery adjacent to the plant. The petroleum coke is gasified to produce a hydrogen rich synthetic gas, from which ammonia and urea ammonium nitrate fertilizers are subsequently synthesized.

As a by-product of manufacturing fertilizers, the plant also produces significant amounts of CO_2. In March 2011, Chaparral Energy announced a long-term agreement for the purchase of captured CO_2 which is transported 68 miles via CO_2 pipeline for use in EOR operations in Osage County, OK. Injection at the site started in 2013.

At least one commenter suggested that the cost and complexity of carbon capture from these and other industrial projects was significantly decreased because the sources already separate CO_2 as part of their normal operations. The EPA finds this argument unconvincing. The Coffeyville process involves gasification of a solid fossil fuel (pet coke), shifting the resulting syngas stream, and separation of the resulting CO_2 using a pre-combustion carbon capture system. These are the same, or very similar, processes that are used in an IGCC EGU. The argument is even less convincing when considering that the Coffeyville Fertilizer process uses the Selexol™ pre-combustion capture process—the same process that Mississippi Power described as having been ''in commercial use in the chemical industry for decades'' and is expected by Mississippi Power to ''pose little technology risk'' when used at the Kemper IGCC EGU.

4. Pre-Combustion Carbon Capture Projects That Have Received DOE Assistance Through EPAct05 and Tax Credits Under IRC Section 48A

a. Kemper County Energy Facility

Southern Company's subsidiary Mississippi Power has constructed the Kemper County Energy Facility in Kemper County, MS. This is a 582 MW IGCC plant that will utilize local Mississippi lignite and includes a pre-combustion carbon capture system to reduce CO_2 emissions by approximately 65 percent. The pre-combustion solvent, Selexol™ has also been used extensively for acid gas removal (including for CO_2 removal) in various processes. In filings with the Mississippi Public Service Commission for the Kemper project, Mississippi described the carbon capture system:

> The Kemper County IGCC Project will capture and compress approximately 65% of the Plant's CO_2 [. . .] a process referred to as Selexol™ is applied to remove the CO_2 such that it is suitable for compression and delivery to the sequestration and EOR process. [. . .] *The carbon capture equipment and processes proposed in this project have been in commercial use in the chemical industry for decades and pose little technology risk.* (emphasis added)[224]

Thus, Mississippi Power believes that, because the Selexol™ process has been in commercial use in the chemical industry for decades, it is well proven, and will pose little technical risk when used in the Kemper IGCC EGU.

b. Texas Clean Energy Project and Hydrogen Energy California Project

The Texas Clean Energy Project (TCEP), a 400 MW IGCC facility located near Odessa, Texas will capture 90 percent of its CO_2, which is approximately 3 million metric tons annually. The captured CO_2 will be used for EOR in the West Texas Permian Basin. Additionally, the plant will produce urea and smaller quantities of commercial-grade sulfuric acid, argon, and inert slag, all of which will also be marketed. Summit has announced that they expect to commence construction on the project in 2015.[225] The facility will utilize the Linde Rectisol® gas cleanup process to capture carbon dioxide[226]—the same process that has been deployed for decades, including at the Dakota Gasification facility, a clear indication of the developer's confidence in that technology and further evidence that the Dakota Gasification carbon capture technology is transferable to EGUs.

F. Vendor Guarantees, Industry Statements, Academic Literature, and Commercial Availability

In this section, we describe additional information that supports our determination that CCS is adequately demonstrated to be technically feasible. This includes performance guarantees from vendors, public statements from industry officials, and review of the literature.

1. Performance Guarantees

The D.C. Circuit made clear in its first cases concerning CAA section 111 standards, and has affirmed since then,

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[219] *http://sequestration.mit.edu/tools/projects/greengen.html.*

[220] Buggenum Fact Sheet: Carbon Dioxide Capture and Storage Project, Carbon Capture & Sequestration Technologies @MIT, *http://sequestration.mit.edu/tools/projects/buggenum.html.*

[221] Puertollano Fact Sheet: Carbon Dioxide Capture and Storage Project, Carbon Capture & Sequestration Technologies @MIT, *https://sequestration.mit.edu/tools/projects/puertollanto.html.*

[222] ESI CCS Project Fact Sheet: Carbon Dioxide and Storage Project, Carbon Capture & Sequestration Technologies @MIT, *https://sequestration.mit.edu/tools/projects/esi_ccs.html* and *https://www.globalccsinstitute.com/projects/large-scale-ccs-projects.*

[223] Uthmaniyah CO_2 EOR Demonstration Project, Global CCS Institute, *https://www.globalccsinstitute.com/projects/large-scale-ccs-projects.*

[224] Mississippi Power Company, Kemper County IGCC Certificate Filing, Updated Design, Description and Cost of Kemper IGCC Project, Mississippi Public Service Commission (MPSC) DOCKET NO. 2009–UA–0014, filed December 7, 2009.

[225] ''Odessa coal-to-gas power plant to break ground this year'', Houston Chronicle (April 1, 2015).

[226] *http://www.texascleanenergyproject.com/project/.*

that performance guarantees from vendors are an important basis for supporting a determination that pollution technology is adequately demonstrated to be technically feasible. In 1973, in *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973), the Court upheld standards of performance for coal-fired steam generators based on ''prototype testing data and full-scale control systems, considerations of available fuel supplies, literature sources, and *documentation of manufacturer guarantees and expectations*'' (emphasis supplied)).[227] Subsequently, in *Sierra Club* v. *Costle,* the Court noted, in upholding the standard: ''we find it informative that the vendors of FGD equipment corroborate the achievability of the standard.'' [228]

Linde and BASF offer performance guarantees for carbon capture technology. The two companies are jointly marketing new, advanced technology for capturing CO_2 from low pressure gas streams in power or chemical plants. In product literature,[229] they note that Linde will provide a turn-key carbon capture plant using a scrubbing process and solvents developed by BASF, one of the world's leading technical suppliers for gas treatment. They further note that:

> The captured carbon dioxide can be used commercially for example for EOR (enhanced oil recovery) or as a building block for the production of urea. Alternatively it can be stored underground as a carbon abatement measure. [. . .] The PCC (Post-Combustion Capture) technology *is now commercially available* for lignite and hard coal fired power plant [. . .] applications.
>
> The alliance between Linde, a world-leading gases and engineering company and BASF, the chemical company, offers great benefits [. . .] Complete capture plants including CO_2 compression and drying . . . Proven and tested processes *including guarantee . . .* Synergies between process, engineering, construction and operation . . . Optimized total and operational costs for the owner. (emphasis added)

In addition, other well-established companies that either offer technologies that are actively marketed for CO_2 capture from fossil fuel-fired power plants or that develop those power plants, have publicly expressed confidence in the technical feasibility of carbon capture. For example, Fluor has developed patented CO_2 recovery technologies to help its clients reduce GHG emissions. The Fluor product literature [230] specifically points to the Econamine FG Plus^{SM} (EFG+) process, which uses an amine solvent to capture and produce food grade CO_2 from post-combustion sources. The literature further notes that EFG+ is also used for carbon capture and sequestration projects, that the proprietary technology provides a proven, cost-effective process for the removal of CO_2 from power plant flue gas streams, and that the process can be customized to meet a power plant's unique site requirements, flue gas conditions, and operating parameters.

Fluor has also published an article titled ''Commercially Available CO_2 Capture Technology'' in which it describes the EFG+ technology.[231] The article notes, ''Technology for the removal of carbon dioxide (CO_2) from flue gas streams has been around for quite some time. The technology was developed not to address the GHG effect but to provide an economic source of CO_2 for use in enhanced oil recovery and industrial purposes, such as in the beverage industry.''

Mitsubishi Heavy Industries (MHI) offers a CO_2 capture system that uses a proprietary energy-efficient CO_2 absorbent called KS–1™. Compared with the conventional monoethanolamine (MEA)-based absorbent, KS–1™ solvent requires less solvent circulation to capture the CO_2 and less energy to recover the captured CO_2.

In addition, Shell has developed the CANSOLV CO_2 Capture System, which Shell describes in its product literature [232] as a world leading amine based CO_2 capture technology that is ideal for use in fossil fuel-fired power plants where enormous amounts of CO_2 are generated. The company also notes that the technology can help refiners, utilities, and other industries lower their carbon intensity and meet stringent GHG abatement regulations by removing CO_2 from their exhaust streams, with the added benefit of simultaneously lowering SO_2 and NO_2 emissions.

At least one commenter suggested that it is unlikely that any vendor is willing or able to provide guarantees of the performance of the system as a whole, arguing that this shows the system isn't adequately demonstrated.[233] However, this suggestion is inconsistent with the performance guarantees offered for other air pollution control equipment. Particulate matter (PM) is controlled in the flue gas stream of a coal-fired power plant using fabric filters or electrostatic precipitators (ESP). The captured PM is then moved using PM/ash handling systems and is then transported for storage or re-use. It is unlikely that a fabric filter or ESP vendor would provide a performance guarantee for ''the system as a whole.'' Similarly, a wet-FGD scrubber vendor would not be expected to provide a performance guarantee for handling, transportation, and re-use of scrubber solids for gypsum wallboard manufacturing. CO_2 capture, transportation, and storage should, similarly, not be viewed as a single technology. Rather, these should be viewed as components of an overall system of emission reduction. Different companies will have expertise in each of these components, but it is unlikely that a single technology vendor would provide a guarantee for ''the system as a whole.''

2. Academic and Other Literature

Climate change mitigation options—including CCS—are the subject of great academic interest, and there is a large body of academic literature on these options and their technical feasibility. In addition, other research organizations (*e.g.,* U.S. national laboratories and others) have also published studies on these subjects that demonstrate the availability of these technologies. A compendium of relevant literature is provided in a Technical Support Document available in the rulemaking docket.[234]

3. Additional Statements by Technology Developers

The discussion above of vendor guarantees, positive statements by industry officials, and the academic literature supports the EPA's determination that partial CCS is adequately demonstrated to be

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[227] *See* also *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 401–02 (D.C. Cir. 1973) (''It would have been entirely appropriate if the Administrator had justified the standards . . . on testimony from experts and vendors made part of the record.'').

[228] *Sierra Club* v. *Costle,* 657 F.2d 298, 364 (D.C. Cir. 1981). *See* also *National Petrochem & Refiners Assn* v. *EPA,* 287 F. 3d 1130, 1137 (D.C. Cir. 2002) (noting that vendor guarantees are an indicia of availability and achievability of a technology-based standard since, notwithstanding a desire to promote sales, ''a manufacturer would risk a considerable loss of reputation if its technology could not fulfill a mandate that it had persuaded EPA to adopt'').

[229] *www.intermediates.basf.com/chemicals/web/gas-treatment/en/function/conversions:/publish/content/products-and-industries/gas-treatment/images/Linde_and_BASF-Flue_Gas_Carbon_Capture_Plants.pdf.*

[230] *www.fluor.com/client-markets/energy-chemicals/Pages/carbon-capture.aspx.*

[231] *http://www.powermag.com/commercially-available-co2-capture-technology/.*

[232] *http://www.shell.com/global/products-services/solutions-for-businesses/globalsolutions/shell-cansolv/shell-cansolv-solutions/co2-capture.html.*

[233] Comments of Murray Energy, p. 73, (Docket entry: EPA–HQ–OAR–2013–0495–10046).

[234] Technical Support Document—''Literature Survey of Carbon Capture Technology'', available in the rulemaking docket (Docket ID: EPA–HQ–OAR–2013–0495).

technically feasible. Industry officials have made additional positive statements in conjunction with facilities that received DOE assistance under EPAct05 or the IRC Section 48A tax credit. These statements provide further, although not necessary, support.

For example, Southern Company's Mississippi Power has stated that, because the Selexol™ process has been used in industry for decades, the technical risk of its use at the Kemper IGCC facility is minimized. For example:

> The carbon capture process being utilized for the Kemper County IGCC is a commercial technology referred to as Selexol™. The Selexol™ process is a commercial technology that uses proprietary solvents, but is based on a technology and principles that have been in commercial use in the chemical industry for over 40 years. Thus, the risk associated with the design and operation of the carbon capture equipment incorporated into the Plant's design is manageable.[235]
>
> And . . .
>
> The carbon capture equipment and processes proposed in this project have been in commercial use in the chemical industry for decades and pose little technology risk.[236]

Similarly, in an AEP Second Quarter 2011 Earnings Conference Call, Chairman and CEO Mike Morris said of the Mountaineer CCS project:

> We are encouraged by what we saw, we're clearly impressed with what we learned, and we feel that we have demonstrated to a certainty that the carbon capture and storage is in fact viable technology for the United States and quite honestly for the rest of the world going forward.[237]

Some commenters have claimed that CCS technology is not technically feasible, and some further assert that vendors do not offer performance guarantees. For example, Alstom commented:

> The EPA referenced projects fail to meet the 'technically feasible' criteria. These technologies are not operating at significant scale at any site as of the rule publication. We do not support mandating technology based on proposed projects (many of which may never be built).[238]

As discussed above, vendors do in fact offer performance guarantees. We further note that, as noted above, Boundary Dam Unit #3 is a full-scale project that is successfully implementing full CCS with post-combustion capture, and Dakota Gasification is likewise a full-scale commercial operation that is successfully implementing pre-combustion CCS technology. Moreover, as we explain above, this technology and performance is transferable to the steam electric generating sector. In addition, as noted above, technology providers and technology end users have expressed confidence in the availability and performance of CCS technology.[239]

G. Response to Key Comments on the Adequacy of the Technical Feasibility Demonstration

1. Commercial Availability

Some commenters asserted that CCS cannot be considered the BSER because it is not commercially available. There is no requirement, as part of the BSER determination, that the EPA finds that the technology in question is ''commercially available.'' As we described in the January 2014 proposal, the D.C. Circuit has explained that a standard of performance is ''achievable'' if a technology or other system of emission reduction can reasonably be projected to be available to new sources at the time they are constructed that will allow them to meet the standard, and that there is no requirement that the technology ''must be in routine use somewhere.'' See *Portland Cement* v. *Ruckelshaus,* 486 F. 2d at 391; 79 FR 1463. In any case, as discussed above, CCS technology is available through vendors who provide performance guarantees, which indicates that in fact, CCS is commercially available, which adds to the evidence that the technology is adequately demonstrated to be technically feasible. In sum, ''[t]he capture and CO_2 compression technologies have commercial operating experience with demonstrated ability for high reliability.''[240]

2. Must a technology or system of emission reduction be in full-scale use to be considered demonstrated?

Commenters maintained that the EPA can only show that a BSER is ''adequately demonstrated'' using operating data from the technology or system of emission reduction itself. This is mistaken. Since the very inception of the CAA section 111 program, courts have noted that ''[i]t would have been entirely appropriate if the Administrator had justified the standard, not on the basis of tests on existing sources or old test data in the literature, but on extrapolations from this data, on a reasoned basis responsive to comments, and on testimony from experts and vendors . . . .'' *Portland Cement* v. *Ruckelshaus,* 486 F. 2d at 401–02.[241]

In a related argument, other commenters stated that a system cannot be adequately demonstrated unless all of its component parts are operating together.[242] Courts have, in fact, accepted that the EPA can legitimately infer that a technology is demonstrated as a whole based on operation of component parts which have not, as yet, been fully integrated. *Sur Contra la Contaminacion* v. *EPA,* 202 F. 3d 443, 448 (1st Cir. 2000); *Native Village of Point Hope v Salazar* 680 F. 3d 1123, 1133 (9th Cir. 2012). Moreover, all components of CCS are fully integrated at Boundary Dam: Post-combustion full CCS is being utilized at a steam electric fossil fuel-fired plant, with captured carbon being transported via dedicated pipeline to both sequestration and EOR sites. All components are likewise demonstrated for pre-combustion CCS at the Dakota Gasification facility, except that the facility does not generate electricity, a distinction without a difference for this purpose (see Section V.E.2.a above).

The short of it is that the ''EPA does have authority to hold the industry to a standard of improved design and

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[235] Testimony of Thomas O. Anderson, Vice President, Generation Development for Mississippi Power, MS Public Service Commission Docket 2009–UA–14 at 22 (Dec. 7, 2009).

[236] Mississippi Power Company, Kemper County IGCC Certificate Filing, Updated Design, Description and Cost of Kemper IGCC Project, Mississippi Public Service Commission (MPSC) DOCKET NO. 2009–UA–0014, filed December 7, 2009.

[237] American Electric Power Co Inc AEP Q2 2011 Earnings Call Transcript, Morningstar, *http://www.morningstar.com/earnings/28688913-american-electric-power-co-incaep-q2–2011-earnings-call-transcript.aspx.*

[238] Alstom Comments, p. 3 (Docket entry: EPA–HQ–OAR–2013–0495–9033).

[239] We note that before filing comments for this rule asserting that CCS is not technically feasible, Alstom issued public statements that, like the other industry officials quoted above, affirmed that CCS is technically feasible. According to an Alstom Power press release, Alstom President Phillipe Joubert, referencing results from an internal Alstom study, stated at an industry meeting: ''We can now be confident that carbon capture technology (CCS) works and that it is cost-effective''. *http://www.alstom.com/press-centre/2011/6/2011-06-16-CCS-cost-competiveness/.*

[240] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3'', DOE/NETL–2015/1723 (July 2015) at p. 36.

[241] More recently, the D.C. Circuit stated:

> Our prior decisions relating to technology-forcing standards are no bar to this conclusion. We recognize here, as we have recognized in the past, that an agency may base a standard or mandate on future technology when there exists a rational connection between the regulatory target and the presumed innovation.

API v. *EPA,* 706 F. 3d at 480 (D.C. Cir. 2013) (citing the section 111 case *Sierra Club* v. *Costle,* 657 F. 2d at 364). The Senate Report to the original section 111 likewise makes clear that it was not intended that the technology ''must be in actual routine use somewhere.'' Rather, the question was whether the technology would be available for installation in new plants. S. Rep. No. 91–1196, 91st Cong., 2d Sess. 16 (1970).

[242] See, *e.g.,* Comments of UARG p. 5 (Docket entry: EPA–HQ–OAR–2013–0495–9666).

operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard.'' *Sierra Club,* 657 F. 2d at 364. The EPA's task is to ''identify the major steps necessary for development of the device, and give plausible reasons for its belief that the industry will be able to solve those problems in the time remaining''. *API* v. *EPA,* 706 F. 3d at 480 (quoting *NRDC* v. *EPA,* 655 F. 2d 318, 333 (D.C. Cir. 1981), and citing *Sierra Club* for this proposition).

3. Scalability of Pilot and Demonstration Projects

Commenters maintained that the EPA had no basis for maintaining that pilot and demonstration plant operations showed that CCS was adequately demonstrated. This is mistaken. In a 1981 decision, *Sierra Club* v. *Costle,* the D.C. Circuit explained that data from pilot-scale, or less than full-scale operation, can be shown to reasonably demonstrate performance at full-scale operation, although it is incumbent on the EPA to explain the necessary steps involved in scaling up a technology and how any obstacles may reasonably be surmounted when doing so.[243] The EPA has done so here.

Most obviously, the final standard reflects experience of full-scale operation of post-combustion carbon capture. Pre-combustion carbon capture is likewise demonstrated at full-scale. Second, the record explains in detail how CCS can be implemented at full-scale. The NETL cost and performance reports, indeed, contain hundreds of pages of detailed, documented explanation of how CCS can be implemented at full-scale for both utility boiler and IGCC facilities. See, for example, the detailed description of the following systems projected to be needed for a new supercritical PC boiler to capture CO_2: Coal and sorbent receiving and storage, steam generator and ancillaries, NO_X control system, particulate control, flue gas desulfurization, flue gas system, CO_2 recovery facility, steam turbine generator system, balance of plant, and accessory electric plant, and instrumentation and control systems.[244]

It is important to note that, while some commenters challenged the EPA's use of costs in the DOE/NETL cost and performance reports, commenters did not challenge the technical methodology in the work.

In addition, the AEP FEED study indicates how the development scale post-combustion CCS could be successfully scaled up to full-scale operation. See Section V.D.3.b above.

Tenaska Trailblazer Partners, LLC also prepared a FEED study[245] for the carbon capture portion of the previously proposed Trailblazer Energy Center, a 760 MW SCPC EGU that was proposed to include 85 to 90 percent CO_2 post-combustion capture. Tenaska selected the Fluor Econamine FG Plus^{SM} technology and contracted Fluor to conduct the FEED study. One of the goals of the FEED study was to ''[c]onfirm that scale up to a large commercial size is achievable.'' Tenaska ultimately concluded that the study had achieved its objectives resulting in ''[c]onfirmation that the technology can be scaled up to constructable design at commercial size through (1) process and discipline engineering design and CFD (computational fluid dynamics) analysis, (2) 3D model development, and (3) receipt of firm price quotes for large equipment.''

Much has been written about the complexities of adding CCS systems to fossil fuel-fired power plants. Some of these statements come from high government officials. Some commenters argued that the EPA minimized—or even ignored—these publically voiced concerns in the discussion presented in the January 2014 proposal. On the contrary, the EPA has not minimized or ignored these complexities, but it is important to realize that most of these statements come in a different context: Namely, implementing full CCS, or retrofitting CCS onto existing power plants. For example, in the Final Report of the President's CCS Task Force, it was noted that ''integration of CCS technologies with the power cycle at generating plants can present significant cost and operating issues that will need to be addressed to facilitate widespread, cost-effective deployment of CO_2 capture.''[246] This statement—and most of the statements in this vein—are in reference to implementation of full CCS systems that capture more than 90 percent of the CO_2 and many reference widespread implementation of such technology. The EPA has addressed the concerns regarding ''significant cost'' by finalizing a standard that relies on partial CCS which we show, in this preamble and in the supporting record, can be implemented at a reasonable, non-exorbitant cost. The Boundary Dam facility, in particular, demonstrates that the complexities of implementing CCS—even full CCS—can be overcome.

Concerns regarding ''operating issues'' are also often associated with implementation of full CCS—and often with implementation of full CCS as a retrofit to an existing source. Implementation of CCS at some existing sources may be challenging because of space limitations. That should not be an issue for a new facility because the developer will need to ensure that adequate space is available during the design of the facility. Constructing CCS technology at an existing facility can be challenging even if there is adequate space because the positioning of the equipment may be awkward when it must be constructed to fit with the existing equipment at the plant. Some commenters noted the challenges of diverting steam from the plant's steam cycle. Again, that is primarily an issue with full CCS implementation as a retrofit to an existing source. Consideration of steam requirements for solvent regeneration can be factored into the design of a new facility. We also note that issues of integration with the plant's steam cycle are less challenging when implementing partial CCS.

Some commenters noted conclusions and statements from the CCS Task Force report as contradictory to the EPA's determination of that partial CCS is technically feasible and adequately demonstrated. However, the EPA mentioned in the January 2014

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[243] *Sierra Club* v. *Costle,* 657 F. 2d 298, 341 n.157 and 380–84 (D.C. Cir. 1981). See also *Essex Chemical Corp.* v. EPA, 486 F. 2d at 440 (upholding achievability of standard of performance for coal-burning steam generating plants which hadn't been achieved in full-scale performance based in part on ''prototype testing data'' which, along with vendor guarantees, indicated that the promulgated standard was achievable); *Weyerhaeuser* v. *Costle,* 590 F. 2d 1054 n. 170 (D.C. Cir. 1978) (use of pilot plant information to justify technology-based standard for Best Available Technology Economically Achievable under section 304 of the Clean Water Act); *FMC Corp.* v. *Train,* 539 F. 2d 973, 983–84 (4th Cir. 1976)(same).

[244] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity; Revision 2a, pp. 57–74.

[245] Final front-end engineering design (FEED) study report'', available at: *www.globalccsinstitute.com/publications/tenaska-trailblazer-front-end-engineering-design-feed-study.*

[246] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 28. See also DOE Carbon Capture Web site: ''First generation CO_2 capture technologies are currently being used in various industrial applications. However, in their current state of development, these technologies are not ready for implementation on coal-based power plants because they have not been demonstrated at appropriate scale, requisite approximately one-third of the plant's steam power to operate, and are cost prohibitive.'' (Dec 2010); and Testimony of Dr. S. Julio Friedmann, Deputy Asst. Secretary of Energy for Clean Coal, U.S. Dept. of Energy, before the Subcommittee on Oversight and Investigations Committee on Energy and Commerce (Feb. 11, 2014): CCS technologies at new coal-fired plants would result in ''something like a 70 to 80 percent increase on the wholesale price of electricity.''

proposal, and we emphasize again here, that the Task Force was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS by 2020. Implicit in all of the conclusions, recommendations, and statements of that final report is a goal of widespread implementation of full CCS—including retrofits of existing sources. This final action does not require—nor does it envision—the near term widespread implementation of full CCS. On the contrary, as we have noted several times in this preamble, the EPA and others predict that very few, if any, new coal-fired steam generating EGUs will be built in the near term.

Thus, the EPA has provided an ample record supporting its finding that partial CCS is feasible at full-scale. As in *Sierra Club,* the EPA has presented evidence from full-scale operation, smaller scale installations, and reasonable, corroborated technical explanations of how the BSER can be successfully operated at full scale. See 657 F. 2d at 380, 382. Indeed, the EPA has more evidence here, as the baghouse standard in *Sierra Club* was justified based largely on less-than-full-scale operation. See 657 F.2d at 380 (there was only ''limited data from one full scale commercial sized operation''), 376 (''the baghouses surveyed were installed at small plants''), and 341 n.157; see also Section V.L, explaining why CCS is a more developed technology than FGD scrubbers were at the inception of the 1971 NSPS for this industry.

H. Consideration of Costs

CAA section 111(a) defines ''standard of performance'' as an emission standard that reflects the best system of emission reduction that is adequately demonstrated, ''taking into account [among other things] the cost of achieving such reduction.'' Based on consideration of relevant cost metrics in the context of current market conditions, the EPA concludes that the costs associated with the final standard are reasonable.

In reaching this determination, the EPA considered a host of different cost metrics, each of which illuminated a particular aspect of cost consideration, and each of which demonstrated that the costs of the final standard are reasonable. The EPA evaluated capital costs on a per-plant basis, responding to public comment that noted the particular significance of capital costs for coal-fired EGUs. As in the proposal, the EPA also considered how the standard would affect the LCOE for individual affected EGUs as well as national, overall cost impacts of the standard. The EPA found that the anticipated cost impacts are similar to those in other promulgated NSPS—including for this industry—that have been upheld by the D.C. Circuit. The costs are also comparable to those of other base load technologies that might be selected on comparable energy portfolio diversity grounds. Finally, the EPA does not anticipate any significant overall nationwide costs or cost impacts on consumers because projected new generating capacity is expected to meet the standards even in the baseline. Accordingly, after considering costs from a range of different perspectives, the EPA concludes that the costs of the final standard are reasonable.

1. Rationale at Proposal

At proposal, the EPA evaluated the costs of new coal-fired EGUs implementing full (90 percent) and partial CCS. The EPA compared the predicted LCOE of those units against the LCOE of other new dispatchable technologies often considered for new base load power with fuel diversity, primarily including a new nuclear plant, as well as a new biomass-fired EGU. See 79 FR at 1475–78. The levelized cost for a new steam EGU implementing full CCS was higher than that of the other non-NGCC dispatchable technologies, and we did not propose to identify a new steam EGU implementing full CCS as BSER on that basis. Id. at 1477. The EPA proposed that a standard of performance of 1,100 lb CO_2/MWh-g, reflecting a new steam EGU implementing partial CCS, could be achieved at reasonable cost based on a comparison of the projected LCOE associated with achieving this standard with the alternative dispatchable technologies just mentioned. In the January 2014 proposal, the EPA used LCOE projections for new fossil fuel-fired EGUs from a series of studies conducted by the DOE NETL. These studies—the ''cost and performance studies''—detail expected costs and performance for a range of technology options both with and without CCS.[247] The EPA used LCOE projections for non-fossil dispatchable generation—specifically nuclear and biomass—from the EIA AEO 2013. See 79 FR 1435.

In addition, the EPA proposed that the costs to implement partial CCS were reasonable because a segment of the industry was already accommodating them. *Id.* at 1478. The EPA also considered anticipated decreases in the cost of CCS technologies, the availability of government tax benefits, loan guarantees, and direct expenditures, and the opportunity to generate income from sale of captured CO_2 for EOR. *Id.* at 1478–80. The EPA noted that the proposed standard was not expected to lead to any significant overall costs or effects on electricity prices. *Id.* at 1480–81. The EPA also acknowledged the overall market context, noting that fossil steam EGUs, even without any type of CCS, are significantly more expensive than new natural gas-fired electricity generation, but that some electricity suppliers might include new coal-fired generating sources in their generation portfolio, and would pay a premium to do so. *Id.* at 1478.

2. Brief Summary of Cost Considerations Under CAA Section 111

As explained above, CAA section 111(a) directs the EPA to ''tak[e] into account the cost'' of achieving reductions in determining if a particular system of emission reduction is the best that is adequately demonstrated. The statute does not provide further guidance on how costs should be considered, thus affording the EPA considerable discretion in choosing a means of cost consideration. In addition, it should be noted that in evaluating the reasonableness of costs, the D.C. Circuit has upheld application of a variety of metrics, such as the amount of control costs or product price increases. See Section III.H.3.(b).(1) above.

Following the directive of CAA section 111(a) and applicable precedent, the EPA evaluated relevant metrics and context in considering the reasonableness of the regulation's costs. The EPA's findings demonstrate that the costs of the selected final standard are reasonable.

3. Current Context

The EIA projects that few new coal-fired EGUs will be constructed over the coming decade and that those that are built will apply CCS, reflecting the broad consensus of government, academic, and industry forecasters.[248]

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[247] For the cost estimates in the January 2014 proposal, the EPA used costs for new SCPC and IGCC units utilizing bituminous coal from the reports ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'', Revision 2, Report DOE/NETL–2010/1397 (November 2010) and ''Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture'', DOE/NETL–2011/1498, May 27, 2011. Additional cost and performance information can be found in additional volumes that are available at *http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.*

[248] Even in its sensitivity analysis that assumes higher natural gas prices and electricity demand, EIA does not project any additional coal beyond its

The primary reasons for this projected trend include low electricity demand growth, highly competitive natural gas prices, and increases in the supply of renewable energy. In particular, U.S. electricity demand growth has followed a downward sloping trend for decades with future growth expected to remain very low.[249] Furthermore, the EPA projects that, for any new fossil fuel-fired electricity generating capacity that is constructed through 2030, natural gas will be the overwhelming fuel of choice.[250] See RIA chapter 4.

The EIA's projection is confirmed by an examination of Integrated Resource Plans (IRPs) contained in a TSD in the docket for this rulemaking. IRPs are used by utilities to plan operations and investments in both owned generation and power purchase agreements over long time horizons. Though IRPs do not demonstrate a utility's intent to pursue a particular generation technology, they do indicate the types of new generating technologies that a utility would consider for new generating capacity. The EPA's survey of recent IRPs demonstrates that across the nation, utilities are not actively considering constructing new coal-fired generation without CCS in the near term.

Accordingly, construction of new uncontrolled coal-fired generating capacity is not anticipated in the near term, even in the absence of the standards of performance we are finalizing in this rule, except perhaps in certain limited circumstances.

In particular, commenters suggested that some developers might choose to build a new coal-fired EGU, despite its not being cost competitive, in order to achieve or maintain ''fuel diversity.'' Fuel diversity could provide important value by serving as a hedge against the possibility that future natural gas prices will far exceed projected levels.

Public announcements, including IRPs, confirm that utilities are interested in technologies that could provide or preserve fuel diversity within generating fleets. The Integrated Resource Plan TSD[251] notes examples where the goal of fuel diversity was considered in IRPs; in many cases, these plans considered new generation that would not rely on natural gas. In particular, several utilities that considered fuel diversity in developing their IRPs included new nuclear generation as a potential future generation strategy.

In addition, the EPA recognizes that there may be interest in constructing a new combined-purpose coal-fired facility that would generate power as well as produce chemicals or CO_2 for use in EOR projects. These facilities would similarly provide additional value due to the revenue streams from saleable chemical products or CO_2.[252]

As demonstrated below, the agency carefully considered the reasonableness of costs in identifying a standard that allows a path forward for such projects and rejects more stringent options that would impose potentially excessive costs. In fact, based on this careful consideration of costs, the EPA is finalizing a substantially lower cost standard than the one we proposed. At the same time, we note the unusual circumstances presented here, where the record, and indeed simple consideration of electricity market economics, demonstrates that non-economic factors such as fuel diversity are likely to drive any construction of new coal-fired generation. See also RIA chapter 4 (documenting that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this rule even in its absence, primarily NGCC units, because of existing and expected market conditions). Under these circumstances, the EPA's consideration of costs takes into account that higher costs can be viewed as reasonable when costs are not a paramount factor in new coal capacity decisions. At the same time, the EPA acknowledges and agrees with the public comments that such an argument, left unconstrained, could justify any standard and obviate all cost considerations.[253] The EPA has reasonably cabined its consideration of costs by examining costs for comparable non-NGCC base load dispatchable technologies, as well as by considering capital costs and other cost metrics.[254] This cost-reasonable standard will preserve the opportunity for such projects while driving new technology deployment.[255]

4. Consideration of Capital Costs

As noted above, CAA section 111 does not mandate any particular method for evaluating costs, leaving the EPA with significant discretion as to how to do so. One method is to consider the incremental capital costs required for a unit to achieve the standard of performance.

The EPA included information on capital cost at proposal and, as discussed further below, the LCOE metric relied upon at proposal and in this final rulemaking incorporates and fully reflects capital costs.[256] Nonetheless, extensive comment from industry representatives and others noted persuasively that fossil-steam units are very capital-intensive projects and recommended that a separate metric, solely of capital costs, be considered by the EPA in evaluating the final standard's costs. Accordingly, the EPA has considered the final standard's impact on the capital costs of new fossil-steam generation. The EPA has determined that the incremental capital costs of the final standard are reasonable because they are comparable to those in prior regulations and to industry experience, and because the fossil steam electric power industry has been shown to be able to successfully absorb capital costs of this magnitude in the past.

Prior new source performance standards for new fossil steam generation units have had significant—yet manageable—impacts on the capital costs of construction. The EPA estimated that the costs for the 1971 NSPS for coal-fired EGUs were $19M for a 600 MW plant, consisting of $3.6M for particulate matter controls, $14.4M for sulfur dioxide controls, and $1M for nitrogen oxides controls, representing a 15.8 percent increase in capital costs

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reference case until 2023, in a case where power companies assume no GHGs emission limitations, and until 2024 in a case where power companies do assume GHGs emission limitations. EIA, ''Annual Energy Outlook 2015,'' DOE/EIA–0383(2015), April 2015, ''[v]ery little unplanned coal-fired capacity is added across all the AEO 2015 cases'', p. 26.

[249] EIA, ''Annual Energy Outlook 2015,'' DOE/EIA–0383(2015), April 2015, p. 8.

[250] Integrated Planning Model (IPM) run by the EPA (v. 5.15) Base Case, available at *www.epa.gov/airmarkets/powersectormodeling.html*.

[251] Technical Support Document—''Review of Electric Utility Integrated Resource Plans'' (May 2015), available in the rulemaking docket EPA–HQ–OAR–2013–0495.

[252] The EPA may, of course, consider revenues generated as a result of application of pollution control measures in assessing the costs of a best system of emission reduction. See *New York* v. *Reilly,* 969 F.2d 1147, 1150–52 (D.C. Cir. 1992).

[253] See, *e.g.,* Comments of Murray Energy, pp. 79–80 (Docket entry: EPA–HQ–OAR–2013–0495–10046).

[254] Indeed, the EPA is not only adopting a standard predicated on a lower rate of carbon capture than proposed, but also rejecting full CCS for reasons of cost. See Section V.P below. Thus, although the EPA has reasonably taken into account the current economic posture of the industry whereby new capacity is not cost-competitive and so would be added for non-economic reasons, it is not using that fact to negate consideration of cost here. See also Section V.I.4 below responding to comments that the incremental cost of partial CCS could prove the difference between constructing and not constructing new coal capacity.

[255] In this rulemaking, our determination that the costs are reasonable means that the costs meet the cost standard in the case law no matter how that standard is articulated, that is, whether the cost standard is articulated through the terms that the case law uses, *e.g.,* ''exorbitant,'' ''excessive,'' etc., or through the term we use for convenience, ''reasonableness.''

[256] See RIA chapter 4.5.4 and Fig. 4–3; see also ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (July 2015) p. 17.

above the $120M cost of the plant. See 1972 Supplemental Statement, 37 FR 5767, 5769 (March 21, 1972). The D.C. Circuit upheld the EPA's determination that the costs associated with the final 1971 standard were reasonable, concluding that the EPA had properly taken costs into consideration. *Essex Cement* v. *EPA,* 486 F. 2d at 440.

In reviewing the 1978 NSPS for coal-fired EGUs, the D.C. Circuit recognized that ''EPA estimates that utilities will have to spend tens of billions of dollars by 1995 on pollution control under the new NSPS'' and that ''[c]onsumers will ultimately bear these costs.'' *Sierra Club,* 657 F.2d at 314. The court nonetheless upheld the EPA's determination that the standard was reasonable. *Id.* at 410.

The cost and investment impacts of the 1978 NSPS on electric utilities were subsequently evaluated in a 1982 Congressional Budget Office (CBO) retrospective study.[257] The CBO study highlighted that installation of scrubbers—capital intensive pollution control equipment that had ''in effect'' been mandated by the 1978 NSPS—increased capital costs for new EGUs by 10 to as much as 20 percent.[258] The study further noted that air pollution control requirements in general had led to an estimated 37.5 to 45 percent increase in capital costs for coal-fired power plant installation between 1971 and 1980.[259]

The study retrospectively confirmed the EPA's conclusion that imposition of these costs was reasonable, finding that ''utilities with commitments to pollution control tend to fare no better and no worse than all electric utilities in general.'' [260] In assessing the capital cost impacts of the suite of 1970s EPA air pollution standards, the report concluded that ''though controlling emissions is indeed costly, it has not played a major role in impairing the utilities' financial position, and is not likely to do so in the future.'' [261]

In NSPS standards for other sectors, the EPA's determination that capital cost increases were reasonable has similarly been upheld. In *Portland Cement Association,* the D.C. Circuit upheld the EPA's consideration of costs for a standard of performance that would increase capital costs by about 12 percent, although the rule was remanded due to an unrelated procedural issue. 486 F.2d at 387–88. Reviewing the EPA's final rule after remand, the court again upheld the standards and the EPA's consideration of costs, noting that ''[t]he industry has not shown inability to adjust itself in a healthy economic fashion to the end sought by the Act as represented by the standards prescribed.'' *Portland Cement* v. *Ruckelshaus,* 513 F. 2d 506, 508 (D.C. Cir. 1975).

The capital cost impacts incurred under these prior standards are comparable in magnitude on an individual unit basis to those projected for the present standard. We predict that the incremental costs of control for a new highly efficient SCPC unit to meet the final emission limitation of 1,400 lb CO_2/MWh-g would be an increase of 21–22 percent for capital costs. See Table 7 below.[262] [263]

TABLE 7—COMPARISON OF ESTIMATED CAPITAL COSTS FOR A NEW SCPC AND A NEW SCPC MEETING THE FINAL STANDARD OF PERFORMANCE [264]

	Total overnight cost (2011$/kW)	Total as-spent capital (2011$/kW)
SCPC—no CCS	2,507	2,842
SCPC—partial CCS (1,400 lb CO_2/MWh-g)	3,042	3,458
Incremental cost increase	21.3%	21.7%

By comparison, a SCPC that co-fires with natural gas to meet the final standard of 1,400 lb CO_2/MWh-g would not result in an increase in capital cost over the uncontrolled SCPC. A compliant IGCC unit co-firing natural gas is predicted to have Total Overnight Cost of $3,036/kW—an approximately 21.1 percent increase in capital over the uncontrolled SCPC unit.

5. Consideration of Costs Based on Levelized Cost of Electricity

As in the proposal, the EPA also considered the reasonableness of costs by evaluating the LCOE associated with the final standard. The LCOE is a commonly used economic metric that takes into account all costs to construct and operate a new power plant over an assumed time period and an assumed capacity factor. The LCOE is a summary metric, which expresses the full cost of generating electricity on a per unit basis (*i.e.,* megawatt-hours). Levelized costs are often used to compare the cost of different potential generating sources. While capital cost is a useful and relevant metric for capital-intensive fossil-steam units, the LCOE can serve as a useful complement because it takes into account all specified costs (operation and maintenance, fuel—as well as capital costs), over the whole lifetime of the project.

As previously mentioned, at proposal the EPA relied on LCOE projections for fossil fuel-fired EGUs (with and without CCS) from DOE/NETL reports detailing the results of studies evaluating the costs and performance of such units. For non-fossil dispatchable generating sources, the EPA relied on LCOE projections from EIA AEO 2013. For this final action, the EPA is relying on updated costs from the same sources. The NETL has provided updated cost and performance information in recently published revisions of reports used in the January 2014 proposal.[265] The updated SCPC cases in the reports include up-to-date cost and performance information from recent vendor quotes

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[257] Congressional Budget Office report, ''The Clean Air Act, the Electric Utilities, and the Coal Market'', April 1982, p. 10–11, 23.

[258] *Id.* at 10–11.

[259] *Id.* at 22.

[260] *Id.* at xvi.

[261] *Id.*

[262] We explain at Section V.I.2 and 3 below the reasonableness of the EPA's cost projections here.

[263] We estimate that a new SCPC EGU using low rank coal (subbituminous coal or dried lignite) would incur a capital cost increase of 23 percent to meet the final standard. See ''Achievability of the Standard for Newly Constructed Steam Generating EGUs'' technical support document available in the rulemaking docket.

[264] Exhibit A–3 (p. 18); ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015).

[265] ''Cost and Performance Baseline for Fossil Energy Plants: Volume 1a'' Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3, U.S. DOE NETL report (2015) and ''Cost and Performance Baseline for Fossil Energy Plants: Volume 1b: Bituminous Coal (IGCC) to Electricity, Revision 2—Year Dollar Update, U.S. DOE NETL report (2015). Both reports are available at *www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.*

and implementation of the Shell Cansolv post-combustion capture process—the process that is currently being utilized at the Boundary Dam #3 facility. The IGCC cost and performance results in the updated reports utilize vendor quotes from the previous report; the costs are adjusted from $2007 to $2011. Important also to note is that DOE/NETL utilized conventional financing for cases without CCS and utilized high-risk financial assumptions for cases that include CCS.[266]

Using information from those reports, the DOE/NETL prepared a separate report summarizing a study that evaluated the cost and performance of various plants designed to meet a range of CO_2 emissions by varying the CO_2 capture rate (*i.e.,* the level of partial capture).[267] The EIA also updated LCOE projections from AEO 2013 to AEO 2014 and again in AEO 2015. Those are discussed in more detail in Section V.I.2.b and d. In evaluating costs for the final standards in this action, the EPA relied primarily on the updated NETL LCOE projections for new fossil fuel-fired EGUs provided in the reports described above and on the LCOE projections for non-fossil, dispatchable generating options from the EIA's AEO 2015.[268] Here, the EPA compared the LCOE of the final standard to the LCOE of analogous potential sources of intermediate and base load power. This comparison demonstrated that the LCOE for a fossil steam unit with partial CCS is within the range of the LCOE of comparable alternative non-NGCC generation sources. In particular, nuclear and biomass generation, which similarly provide both base load power and fuel diversity, have comparable LCOE. The EPA concludes that an evaluation of the LCOE also demonstrates that the costs of the final standard are reasonable.

a. Calculation of the LCOE

The LCOE of a power plant source is calculated with the expected lifetime and average capacity factor, and represents the average cost of producing a megawatt-hour (MWh) of electricity over the expected lifetime of the asset.

The LCOE incorporates all specified costs, and therefore is dependent on the project's capital costs, the fixed and variable operating and maintenance (O&M) costs, the fuel costs, the costs to finance the project, and finally on the assumed capacity factor.[269] The relative contribution of each of these inputs to LCOE will vary among the generating technologies. For example, the LCOE for a new supercritical PC plant or a new IGCC plant is influenced more by the capital costs (and thus the financing assumptions) and less on fuel costs than a comparably sized new NGCC facility which would require less capital investment but would be more influenced by assumed fuel costs.

b. Use of the LCOE

The utility industry and electricity sector regulators often use levelized costs as a summary measure for comparing the cost of different potential generating sources. Use of the LCOE as a comparison measure is appropriate where the facilities being compared would serve load in a similar manner.

The value of generation, as reflected in the wholesale electricity price, can vary seasonally and over the course of a day. In addition, electricity generation technologies differ on dimensions other than just cost, such as ramping efficiency, intermittency, or uncertainty in future fuel costs. These other factors are also important in determining the value of a particular generation technology to a firm, and accordingly cost comparisons between two different technologies are most appropriate and insightful when the technologies align along these other dimensions. Isolating a comparison of technologies based on their LCOE is appropriate when they can be assumed to provide similar services and similar values of electricity generated.

As we indicated in the proposal, we evaluated publicly available IRPs and other available information (such as public announcements) to determine the types of technologies that utilities are considering as options for new generating capacity.[270] In the near future, the largest sources of new fossil fuel-fired power generation are expected to be new NGCC units. But the IRPs also suggested that utilities are interested in a range of technologies that can be used to provide or preserve fuel diversity within the utilities' respective generating fleets.[271] [272] The options for

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[266] Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015) p. 18.

[267] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015). Available at *http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.*

[268] *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[269] See, *e.g.* ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015) at p. 17.

[270] See also discussion at V.C.3 above. The IRPs do not provide an indication of the utility's intention to pursue a particular generation technology. However, the IRPs do provide an indication of the types of new generating technologies that the utility would consider for new generating capacity.

[271] See, *e.g.* the 2014 IRP of Dominion Virginia Power:

With those factors in mind, the 2014 Plan presents two paths forward for resource expansion: a Base Plan, designed using least-cost planning methods and consistent with the requirements of Rule R8–60 for utility plans to provide ''reliable electric utility service at least cost over the planning period;'' and a Fuel Diversity Plan, which includes a broader array of low or zero-emissions options. While the Fuel 2 Diversity Plan currently represents a higher cost option at today's current and projected commodity prices, its resource mix provides the important benefits of greater fuel diversity and lower carbon intensity. Therefore, the Company will continue reasonable development of the more diverse and lower carbon intensive options in the Fuel Diversity Plan and will be ready to implement them as conditions warrant. . . . The Fuel Diversity Plan places a greater reliance on generation sources with little or no carbon emissions and is less reliant on natural gas. While following the resource expansion scenario in the least-cost Base Plan, the Company will continue evaluation and reasonable development efforts for the following projects identified in the Fuel Diversity Plan. These include:

Continued development of a third nuclear reactor at North Anna Power Station, using reactor technology supplied by GE-Hitachi Nuclear Energy Americas LLC. While the Company has made no final commitment to building this unit, it recognizes the many operational and environmental benefits of nuclear power and continues to actively develop the project. Our customers have benefitted from the existing nuclear fleet for many years now, and they will continue to benefit from the existing fleet for many years in the future. A final decision on construction of North Anna Unit 3 will not be made until after the Company receives a Combined Operating License or COL from the U.S. Nuclear Regulatory Commission, now expected in 2016. The Fuel Diversity Plan includes the addition of North Anna Unit 3's 1,453 megawatts of zero-emissions generation by 2028. If constructed, the project would provide a dramatic boost to the regional economy.

Additional reliance on renewable energy, including 247 megawatts of onshore wind capacity at sites in western Virginia and a 12 megawatt offshore wind demonstration project by 2018.

An additional 559 megawatts of nameplate solar capacity, including several new Company-owned photovoltaic CPV) installations. Solar PV costs have declined significantly in recent years, making utility-scale solar much more cost-effective than distributed solar, and continuing technological development, in which the Company is participating, may allow it to become a more cost-effective source of intermittent generation in the future.cover letter for 2014 IRP—*https://www.dom.com/library/domcom/pdfs/corporate/integrated-resource-planning/va-irp-2014.pdf.*

[272] Another example are the recent statements of officials of Tri-State Generation and Transmission, available at *http://www.wyofile.com/coal-power/*, including:

''We are considering nuclear, coal and natural gas,'' said Ken Anderson, general manager of Tri-State at a conference in October [2010], a position that Tri-State representatives say remains. ''We will pick our technology once policy certainty comes about,'' he added. . . . Longer-term forecasts are based on assumptions that may or may not prove well-founded. Because of this uncertainty, Tri-State believes it must retain options for all fuels and technologies.

''We will not take anything off the table,'' [Tri-State spokesman Lee] Boughey said. That includes coal. ''Coal is an affordable and plentiful resource, but it does come with challenges—and we are

Continued

dispatchable generation that can provide intermediate or base-load power and fuel diversity would include new fossil steam units, new nuclear power, and biomass-fired generation.

Thus, in both the proposal and in this final rule, the EPA is comparing the LCOE of technologies that would be reasonably anticipated to be designed, constructed, and operated for a similar purpose—that is, to provide dispatchable base load power that provides fuel diversity by relying on a fuel source other than natural gas. In contrast, it may not be appropriate to compare the LCOE for a base load coal-fired plant with that of a peaking natural gas-fired simple cycle turbine. Similarly, it may not be appropriate to compare LCOE for dispatchable technologies (*i.e.,* generating sources that can be ramped up or down as needed, *e.g.,* coal-fired units, NGCC units, nuclear) with that of non-dispatchable technologies (*i.e.,* generating sources that cannot be reliably ramped up or down to meet demand, *e.g.,* wind, solar.)

c. Reasonableness of Costs Based on LCOE

An examination of the LCOE of analogous sources of base load, dispatchable power shows that the final standard's LCOE is comparable to that of other sources, as shown in Table 8 below. As mentioned earlier and discussed in further detail below, these estimates rely most heavily on DOE/NETL cost projections for fossil fuel generating technologies and on the updated EIA AEO 2015 for non-fossil generation technologies. Recent estimates from Lazard[273] [274] are also provided for nuclear and biomass generation options.

TABLE 8—PREDICTED COST AND CO_2 EMISSION LEVELS FOR A RANGE OF POTENTIAL NEW GENERATION TECHNOLOGIES[275]

New generation technology	Emission lb CO_2/MWh-g	LCOE* $/MWh
SCPC—no CCS (bit)	1,620	76–95
SCPC—no CCS (low rank)	1,740	75–94
SCPC + ~16% partial CCS (bit)	1,400	92–117
SCPC + ~23% partial CCS (low rank)	1,400	95–121
Nuclear (EIA)	0	87–115
Nuclear (Lazard)	0	92–132
Biomass (EIA)[276]	—	94–113
Biomass (Lazard)	—	87–116
IGCC	1,430	94–120
NGCC	1,000	** 52–86

* The LCOE ranges presented in Table 8 include an uncertainty of −15%/+30% on capital costs for SCPC and IGCC cases and an uncertainty of −10%/+30% on capital costs for nuclear and biomass cases from EIA. This reflects information provided by EIA. Nuclear staff experts expect that nuclear plants currently under construction would not have capital costs under estimates and that one could expect to see a 30% "upside" variation in capital cost. There is also insufficient market data to get a good statistical range of potential capital cost variation (*i.e.* only 2 plants under construction, neither complete). The nuclear cost estimates from Lazard likewise reflect the range of expected nuclear costs. LCOE estimates displayed in this table for SCPC units with partial CCS as well as for IGCC units use a higher financing cost rate in comparison to the SCPC unit without capture.[277]

** This range represents a natural gas price from $5/MMBtu to $10/MMBtu.

As shown in Table 8, we project that the LCOE for new fossil steam capacity meeting the final 1,400 lb CO_2/MWh-g standard to be substantially similar to that for a new nuclear unit, the principal other alternative to natural gas to provide new base load power. This is the case for new units firing bituminous and subbituminous coals and dried lignite. This is another demonstration that the costs of the final standard are reasonable because nuclear and fossil steam generation each would serve an analogous role in adding dispatchable base load generation diversity—or at least non-NGCC alternatives—to a power provider's portfolio; hence, they are reasonably viewed as comparable alternatives.[278]

As previously mentioned, the DOE/NETL assumed conventional financing

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looking to different technology that can address some of those challenges while continuing to provide a reliable and affordable power supply,'' Boughey said. ''Some critics believe we shouldn't be looking at resource options that include coal, and even nuclear technology,'' Boughey added. ''We believe it would be irresponsible not to consider these fuels or technologies as part of an affordable, reliable and responsible resource portfolio.''

[273] Lazard's Levelized Cost of Energy Analysis—Version 8.0; September 2014; available at: *http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf* and in the rulemaking docket.

[274] Lazard is one of the world's preeminent financial advisory and asset management firms. Lazard's Global Power, Energy & Infrastructure Group serves private and public sector clients with advisory services regarding M&A, financing, and other strategic matters. The group is active in all areas of the traditional and alternative energy industries, including regulated utilities, independent power producers, advanced transportation technologies, renewable energy technologies, meters, smart grid and energy efficiency technologies, and infrastructure. *http://www.marketwatch.com/story/lazard-releases-new-levelized-cost-of-energy-analysis-2014-09-18*.

[275] LCOE cost estimates for SCPC and IGCC cases come from ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'' DOE/NETL–2015/1720 (June 22, 2015). Cost and performance for low rank SCPC is adapted from ''Cost and Performance Baseline for Fossil Energy Plants Volume 3 Executive Summary: Low Rank Coal and Natural Gas to Electricity'', DOE/NETL–2010/1399 (September 2011). LCOE cost estimates for nuclear and biomass are derived from ''Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015'', June 2015, *www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf*. LCOE cost estimates for NGCC technology are EPA estimates based on a range of potential natural gas prices.

[276] Table 8 includes LCOE figures for biomass-fired generation, a potential sources of dispatchable base load power that is not fueled by natural gas. The EPA includes this information for completeness, while noting that biomass-fired units in operation in the U.S. are smaller scale and thus are not as robust analogues as nuclear power. CO_2 emissions are not provided for biomass units because different biomass feedstocks have different net CO_2 emissions; therefore a single emission rate is not appropriate to show in Table 8.

[277] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015) at p. 18.

[278] LCOE comparisons of reasonably available compliance alternatives—IGCC with natural gas co-firing, and SCPC with natural gas co-firing—are found below in Table 9. As shown there, these alternatives are either lower cost than SCPC with partial CCS, or of comparable cost.

for cases without CCS and assumed high-risk financing for cases with some level of CCS. Specifically a high-risk financial structure resulting in a capital charge factor (CCF) of 0.124 is used in the study to evaluate the costs of all cases with CO_2 capture (non-capture case uses a conventional financial structure with a CCF of 0.116).[279] As a comparison of how this affects the resulting DOE/NETL costs, a new SCPC utilizing 16 percent partial CCS is projected to have an LCOE of $99/MWh (including transportation and storage costs; does not include the range for uncertainty). That projected LCOE includes the ''high risk financial assumptions''. If the LCOE for that unit were to be calculated using the ''conventional financing assumptions'', the resulting LCOE would be $94/MWh.

This approach is in contrast to that taken by the EIA which applies a 3-percentage-point cost of capital premium (the 'climate uncertainty adder') to non-capture coal plants to reflect the market reaction to potential future GHG regulation.

Under current and anticipated market conditions, power providers that are considering costs alone in choosing a fuel source for new intermediate or base load generation will choose natural gas because of its competitive current and projected price. However, as noted in Section V.H.3, public IRPs indicate that utilities are considering and selecting technologies that could provide or preserve fuel diversity within generating fleets. For example, utilities have been willing to pay a premium for nuclear power in certain circumstances, as indicated by the recent new constructions of nuclear facilities and by IRPs that include new nuclear generation in their plans. In general, fossil steam and nuclear generation each can provide dispatchable, base load power while also maintaining or increasing fuel diversity.[280] Utilities may be willing to pay a premium for these generation sources because they could serve as a hedge against the possibility that future natural gas prices will far exceed projected levels. Accordingly, the LCOE analysis demonstrates that the final standard's costs are in line with power sources that provide analogous services—dispatchable base load power and fuel diversity.

We further note a number of conservative elements of the costs we used in making this comparison. In particular, these estimates include the highest value in the projected range of potential costs for partial CCS. They do not reflect revenues which can be generated by selling captured CO_2 for enhanced oil recovery, and reflect the costs of partial CCS rather than potentially less expensive alternative compliance paths such as a utility boiler co-firing with natural gas. See also V.H.7 and 8 below.

6. Overall Costs and Economic Impacts

As noted above, an assessment of national costs is also an appropriate means of evaluating the reasonableness of costs under CAA section 111. See *Sierra Club,* 657 F.2d at 330.

The EPA considered the regulation's overall costs and economic impacts as part of its RIA. The RIA demonstrates that these costs would be negligible and that the effects on electricity rates and other market indicators would similarly be minimal.

These results are driven by the existing market context for fossil-steam generation. Even in the absence of the standards of performance for newly constructed EGUs, substantial new construction of uncontrolled fossil steam units is not anticipated under existing prevailing and anticipated future economic conditions. Modeling projections from government, industry, and academia anticipate that few new fossil steam EGUs will be constructed over the coming decade and that those that are built would have CCS.[281] Instead, EIA data shows that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity in the near future.[282] Of the coal-fired units moving forward at various advanced stages of construction and development—Southern Company's Kemper County Energy Facility and Summit Power's Texas Clean Energy Project (TCEP)—each will deploy IGCC with some level of CCS. The primary reasons for this rate of current and projected future development of new coal projects include highly competitive natural gas prices, lower electricity demand, and increases in the supply of renewable energy.

In its RIA, the EPA considered the overall costs of this regulation in the context of these prevailing market trends. Because of the expectation of no new fossil steam generation, the RIA projects that this final rule will result in negligible costs overall on owners and operators of newly constructed EGUs by 2022.[283] More broadly, this regulation is not expected to have significant effects on fuel markets, electricity prices, or the economy as a whole, as described in detail in Chapter 4 of the RIA.

In comparison, courts have upheld past regulations that imposed substantial overall costs in order to protect against uncontrolled emissions. As noted above, in *Sierra Club* v. *Costle,* the D.C. Circuit upheld a standard of performance that imposed costly controls on SO_2 emissions from new coal-fired power plants. 657 F.2d at 410. These standards had implications for the economy ''at the local and national levels,'' as ''EPA estimates that utilities will have to spend tens of billions of dollars by 1995 on pollution control under the new NSPS.'' *Id.* at 314. Further, the court acknowledged that ''[c]onsumers will ultimately bear these costs, both directly in the form of residential utility bills, and indirectly in the form of higher consumer prices due to increased energy costs,'' before concluding that the costs were reasonable. *Id.*

The projected total incremental capital costs associated with the standard we are finalizing in this rule are dramatically lower than was the case for this prior standard, as well as other prior standards summarized previously. For example, when the standard at issue in *Sierra Club* was upheld, the industry was expected to build, and did build, dozens of plants ultimately meeting the standards—at a projected incremental cost of tens of billions of dollars.[284] Here, by contrast, few if any fossil steam EGUs are projected to be built in the foreseeable future, indicating that the total incremental costs are likely to be considerably more modest.

Commenters stated that the cost provision in CAA section 111(a)(1) does not authorize the EPA to consider the nationwide costs of a system of emission reduction in lieu of considering the cost impacts for individual new plants. In this rule, we

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[279] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015) at p. 7.

[280] As another example, San Antonio customers will benefit from low-carbon power from the Texas Clean Energy Project. CPS Energy CEO Doyle Deneby said in a news release: ''*Adding clean coal to our portfolio dovetails with our strategy to diversify and reduce the carbon intensity of the power we supply to our customers.*'' *www.bizjournals.com/sanantonio/news/2014/10/06/cps-energy-strikes-new-deal-to-buy-power-from.html.*

[281] RIA chapter 4. For example, even in the EIA's sensitivity analysis that assumes higher natural gas prices and electricity demand, the EIA does not project any additional coal beyond its reference case until 2023, in a case where power companies assume no GHGs emission limitations, and until 2024 in a case where power companies do assume GHGs emission limitations. AEO 2015.

[282] Annual Energy Outlook 2010, 2011, 2012, 2013, 2014 and 2015.

[283] Conditions in the analysis year of 2022 are represented by a model year of 2020.

[284] *Sierra Club,* 657 F.2d at 314.

are considering both sets of costs and, in fact, we are not identifying full CCS as the BSER primarily for reasons of its cost to individual sources. At the same time, total projected costs are relevant in assessing the overall reasonableness of costs associated with a standard. Our analysis demonstrates that the impacts on the industry as a whole are negligible, and are certainly not greater than ''what the industry could bear and survive.''[285] These facts support the EPA's overall conclusion that the costs of the standard are reasonable.

However, as noted earlier, for a variety of reasons, some companies may consider coal-fired steam generating units that the modeling does not anticipate. Thus, in Chapter 5 of the RIA, we also present an analysis of the project-level costs of a newly constructed coal-fired steam generating unit with partial CCS that meets the requirements of this final rule alongside the project-level costs of a newly constructed coal-fired unit without CCS. This analysis in RIA chapter 5 indicates that the quantified benefits of the standards of performance would exceed their costs under a range of assumptions.

As required under Executive Order 12866, the EPA conducts benefit-cost analyses for major Clean Air Act rules, and has done so here. While such analysis can help to inform policy decisions, as permissible and appropriate under governing statutory provisions, the EPA does not use a benefit-cost test (*i.e.,* a determination of whether monetized benefits exceed costs) as the sole or primary decision tool when required to consider costs or to determine whether to issue regulations under the Clean Air Act, and is not doing so here.[286] Nonetheless, as just noted, the RIA analysis shows that the standard of performance has net quantified benefits under a range of assumptions.

7. Opportunities to Further Reduce Compliance Costs

While the EPA believes, as detailed above, that there is sufficient evidence to show that the final standards of performance for new steam generating units can be met at a reasonable cost, we also note that there are potential opportunities to further reduce compliance costs. We believe that, in most cases, the actual costs will be less than those presented earlier.

As explained in more detail in the following subsection, a new utility boiler can meet the final standard of performance by co-firing with natural gas. Some project developers may choose to utilize natural gas co-firing as a means of delaying, rather than avoiding, implementation of partial CCS. Developers can also choose to install IGCC with a small amount of natural gas co-firing at costs within the range of SCPC with partial CCS, although slightly higher.

The EPA also notes that new units that capture CO_2 will likely be built in areas where there are opportunities to sell the captured CO_2 for some useful purpose prior to (or concomitant with) permanent storage. The DOE refers to this as ''carbon capture, utilization and storage'' or CCUS. In particular, the ability to sell captured CO_2 for use in enhanced oil recovery operations offers the most opportunity to reduce costs. In this regard, the newly-operating Boundary Dam facility is selling captured CO_2 for EOR. The Kemper facility likewise plans to do so.[287]

In some instances, the costs of CCS may be defrayed by grants or other benefits provided by federal or state governments. The need for subsidies to support emerging energy systems and new control technologies is not unusual. Each of the major types of energy used to generate electricity has been or is currently being supported by some type of government subsidy such as tax benefits, loan guarantees, low-cost leases, or direct expenditures for some aspect of development and utilization, ranging from exploration to control installation. This is true for fossil fuel-fired, as well as nuclear-, geothermal-, wind-, and solar-generated electricity. As stated earlier, the EPA considers the costs of partial CCS at a level to meet the final standard of performance to be reasonable even without considering these opportunities to further reduce implementation and compliance costs. We did not in the proposal—and we do not here in this final action—rely on any cost reduction opportunities to justify the costs of meeting the standard as reasonable, but again note the conservative assumptions embodied in our assessment of compliance costs.

a. Cost and Feasibility of Natural Gas Co-firing as an Alternative Compliance Pathway

Although the EPA has determined that implementation of partial CCS at an emission limitation of 1,400 lb CO_2/MWh-g is the BSER for newly constructed fossil fuel-fired steam generating EGUs, we also note that operators can consider the use of natural gas co-firing to achieve the final emission limitation, likely at a lower cost.

At the final emissions limitation of 1,400 lb CO_2/MWh-g a new supercritical PC or supercritical CFB can meet the standard by co-firing with natural gas at levels up to approximately 40 percent (heat input basis) and could potentially avoid (or delay) installation and use of partial CCS altogether.

Natural gas co-firing has long been recognized as an option for coal-fired boilers to reduce emissions of criteria and hazardous air pollutants. EPRI sponsored a study to assess both technical and economic issues associated with natural gas co-firing in coal-fired boilers.[288] They determined that the largest number of applications and the longest experience time is with natural gas reburning and with supplemental gas firing. Natural gas reburning has been used primarily as a NO_X control technology. It is implemented by introducing natural gas (up to 20 percent total fuel heat input) in a secondary combustion zone (called the ''reburn zone'') downstream of the primary combustion zone in the boiler. Injecting the natural gas creates a fuel-rich zone where NO_X formed in the main combustion zone is reduced to nitrogen and water vapor.

Higher levels of natural gas co-firing can be met by utilizing supplemental gas co-firing (either alone or along with natural gas reburning). This involves the simultaneous firing of natural gas and pulverized coal in a boiler's primary combustion zone. Others have also evaluated configurations that would allow coal-fired units to utilize natural gas.[289] [290]

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[285] *Portland Cement Ass'n,* 513 F.2d at 508.

[286] See Memorandum ''Consideration of Costs and Benefits under the Clean Air Act'' available in the rulemaking dockets, EPA–HQ–OAR–2013–0495 (new sources) and EPA–OAR–HQ–2013–0603 (modified and reconstructed sources).

[287] The EPA is referring to the Kemper facility here as an example of how costs can be defrayed, not for use of technology or level of emission reduction achieved. The EPA therefore does not believe that the EPAct05 prevents reference to the fact that Kemper plans to sell captured carbon.

[288] Gas Cofiring Assessment for Coal Fired Utility Boilers; Final Report, August 2000; EPRI Technical Report available at *www.epri.com.*

[289] Many of the studies evaluated opportunities to use natural gas reburn, natural gas co-firing and other configurations in existing coal-fired boilers. Those conclusions would also be applicable for new coal-fired boilers.

[290] ''Dual Fuel Firing—The New Future for the Aging U.S. Based Coal-Fired Boilers'', presented by Riley Power, Inc. at 37th International Technical Conference on Clean Coal and Fuel Systems June 2012 Clearwater, FL, available at *http://www.babcockpower.com/pdf/RPI-TP-0228.pdf.*

A 2013 article entitled ''Utility Options for Leveraging Natural Gas'' [291] noted that:

> Utility owners of coal-fired power stations that wish to balance their exposure to coal-fired generation with additional natural gas-fired generation have several options to consider. The four most practical options are co-firing coal and gas in the same boiler, converting the coal-fired boiler to gas-only operation, repowering the coal plant with natural gas-fired combustion turbines, or replacing the coal plant with a combined cycle plant. [. . .] Co-firing is the lowest-risk option for substituting gas use for coal.

The EPA examined compliance costs for a new steam generating unit to meet the final standard of performance using natural gas co-firing and compared those costs to the estimated costs of meeting the final standards using partial CCS. Those costs are provided below in Table 9.

TABLE 9—PREDICTED COSTS TO MEET THE FINAL STANDARD USING NATURAL GAS CO-FIRING [292]

New generation technology	Emission lb CO_2/MWh-g	LCOE $/MWh
SCPC—no CCS	1,620	82
SCPC + ~16% partial CCS	1,400	99
SCPC + ~34% NG co-fire	1,400	92
IGCC—no CCS	1,434	103
IGCC + ~6% NG co-fire	1,400	105
NGCC*	1,000	60

* The generation cost using NG co-fire and NGCC assume a natural gas price of $6.19/mmBtu.

The EPA thus again notes that the cost assumptions it is making in its BSER determination are conservative. That is, by costing partial CCS as BSER, the EPA may be overestimating actual compliance costs since there exist other less expensive means of meeting the promulgated standard.[293]

Notwithstanding that costs for a SCPC to meet the standard would be lower if it co-fired with natural gas, we have not identified that compliance alternative as BSER because we believe that new coal-fired steam electric generating capacity would be built to provide fuel diversity, and burning substantial amounts of natural gas would be contrary to that objective. In addition, this choice would not promote use of advanced pollution control technology. New IGCC has costs which are comparable to SCPC, as does IGCC with natural gas co-firing,[294] but we are choosing not to identify it as BSER for reasons stated at Sections V.C.2 and V.P: use of IGCC does not advance emission control beyond current levels of performance for sources which may choose to utilize IGCC technology. Nonetheless, use of IGCC remains a viable, demonstrated compliance option to meet the 1,400 lb CO_2/MWh-g standard of performance, and is available at reasonable cost and (as shown at Section V.P below) without significant adverse non-air quality impacts or energy implications.

Costs are Reasonably Expected To Decrease Over Time

The EPA reasonably expects that the costs of CCS will decrease over time as the technology becomes more widely deployed. Although, for the reasons that have been noted, we consider the current costs of CCS to be reasonable, the projected decrease in those costs further supports their reasonableness. The D.C. Circuit case law that authorizes determining the ''best'' available technology on the basis of reasonable future projections supports taking into account projected cost reductions as a way to support the reasonableness of the costs.

We expect the costs of CCS technologies to decrease for several reasons. We expect that significant additional knowledge will be gained from deployment and operation of the new coal-fired generation facilities that are either operating or are nearing completion. These would include the Boundary Dam Unit #3 facility, the Petra Nova WA Parish project, and the Kemper County IGCC facility. The operators of the Boundary Dam Unit #3 are considering construction of additional CCS units and have projected that the next units could be constructed at a cost of at least 30 percent less than that at Unit #3.[295] These savings primarily come from application of lessons learned from the Unit #3 design and construction.

To facilitate the transfer of the technology and to accelerate development of carbon capture technology, SaskPower has created the CCS Global Consortium.[296] This consortium provides SaskPower the opportunity to share the knowledge and experience from the Boundary Dam Unit #3 facility with global energy leaders, technology developers, and project developers. SaskPower, in partnership with Mitsubishi and Hitachi, is also helping to advance CCS knowledge and technology development through the creation of the Shand Carbon Capture Test Facility (CCTF).[297] The test facility will provide technology developers with an opportunity to test new and emerging carbon capture systems for controlling carbon emissions from coal-fired power plants.

The DOE also sponsors testing at the National Carbon Capture Center (NCCC). The NCCC—located at Southern Company's Plant Gaston in Wilsonville, AL—provides first-class facilities to test new capture technologies for extended periods under commercially representative conditions with coal-derived flue gas and syngas.[298]

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[291] Utility Options for Leveraging Natural Gas, 10/01/2013 article in *Power.* Available at *http://www.powermag.com/utility-options-for-leveraging-natural-gas/.*

[292] Costs and emissions for cases that do not utilize natural gas co-firing are from ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015). Costs and emissions for natural gas co-fired cases are EPA estimates.

[293] Certain commenters argued that the proposed standard essentially mandated a sole method of compliance, and hence constituted a work practice for purposes of section 111(h) of the Act. These commenters argued further that the EPA had failed to justify the proposal under the section 111(h) criteria. The EPA disagrees with the premise of these comments, but, in any case, there are clearly multiple compliance paths available for achieving the final standard.

[294] IGCC units already have combined cycle capacity, and so can be readily operated in whole or in part using natural gas as a fuel. Indeed, both the Edwardsport and Kemper IGCC facilities have operated at times by firing exclusively natural gas.

[295] ''Boundary Dam—The Future is Here'', plenary presentation by Mike Monea at the 12th International Conference on Greenhouse Gas Technologies (GHGT–12), Austin, TX (October 2014).

[296] *http://www.saskpowerccs.com/consortium/.*

[297] *www.saskpowerccs.com/ccs-projects/shand-carbon-capture-test-facility/.*

[298] *www.nationalcarboncapturecenter.com/index.html.*

We expect continued additional cost reductions to come from knowledge gained from continued operation of non-power sector industrial projects which, as we have discussed, are informative in transferring the technology to power sector applications. We expect the on-going research and development efforts—such as those sponsored by the DOE/NETL.

Significant reductions in the cost of CO_2 capture would be consistent with overall experience with the cost of pollution control technology. Reductions in the cost of air pollution control technologies as a result of learning-by-doing, reductions in financial premiums related to risk, research and development investments, and other factors have been observed over the decades.

c. Opportunities To Reduce Cost Through Sales of Captured CO_2

Geologic storage options include use of CO_2 in EOR operations, which is the injection of fluids into a reservoir after production yields have decreased from primary production in order to increase oil production efficiency. CO_2-EOR has been successfully used for decades at many production fields throughout the U.S. to increase oil recovery. The use of CO_2 for EOR can significantly lower the net cost of implementing CCS. The opportunity to sell the captured CO_2 for EOR, rather than paying directly for its long-term storage, improves the overall economics of the new generating unit. According to the International Energy Agency (IEA), of the CCS projects under construction or at an advanced stage of planning, 70 percent intend to use captured CO_2 to improve recovery of oil in mature fields.[299] See also Section V.M.3 below.

I. Key Comments Regarding the EPA's Consideration of Costs

In its consideration of the costs associated with the final standard, the EPA considered a range of different cost metrics, each with its individual strengths and weaknesses. As discussed above, each metric supports the EPA's conclusion that the costs of the final standard are reasonable.

In this section, we review the comments received on assessing cost reasonableness and specific cost metrics. We explain how these comments informed our consideration of different metrics and cost reasonableness in general.

1. Use of LCOE as a Cost Metric

As noted, CAA section 111(a) directs the EPA to consider ''cost'' in determining if the BSER is adequately demonstrated. It does not provide further guidance as to how costs are to be considered, thus affording the EPA considerable discretion to choose a reasonable means of cost consideration. See, *e.g. Lignite Energy Council* v. *EPA,* 198 F. 3d at 933. Certain commenters nonetheless argued that LCOE was an impermissible metric because it does not measure the cost of achieving the emission reduction, but rather measures the impact on the product produced by the entity subject to the standard.[300] The EPA does not agree that its authority is so limited. Indeed, in the first decided case under section 111, the D.C. Circuit, in holding that the EPA's consideration of costs was reasonable, specifically noted the EPA's examination of the impact of the standards on the regulated source category's product in comparison to competitive products. *Portland Cement Ass'n* v. *EPA,* 486 F. 2d at 388 (''costs of control equipment could be passed on without substantially affecting competition with construction substitutes such as steel, asphalt, and aluminum'').

Commenters also argued that the choice of LCOE as a cost metric masked consideration of the considerable capital costs associated with CCS. The EPA disagrees with this contention. The LCOE does not mask consideration of capital costs. Rather, as explained at V.H.5 above, LCOE is a summary metric that expresses the full cost (*e.g.,* capital, O&M, fuel) of generating electricity and therefore provides a useful summary metric of costs per unit of production (*i.e.,* megawatt-hours). Provided that those megawatt-hours provide similar electricity services and align on dimensions other than just cost, then the LCOE provides a useful comparison of which technologies are least cost.

The EPA certainly does not minimize that project developers must take capital costs into consideration, and as discussed in Section V.H.4 above, the EPA accordingly has considered direct capital costs here as part of its assessment and found those costs to be reasonable. In addition, the EPA notes that its comparison of the marginal impacts from an individual illustrative facility's compliance with the standard, discussed in detail above and in the RIA Chapter 5, took into account the marginal capital costs that would be incurred by an individual facility.

According to EIA,[301] capital costs represent approximately 63 percent of the LCOE for a new coal-fired SCPC plant; approximately 66 percent of the LCOE for a new IGCC plant; approximately 74 percent of the LCOE for a new nuclear plant; and only about 22 percent of the LCOE for a new NGCC unit. The LCOE of a new NGCC unit is much more strongly affected by fuel costs (natural gas). As we have discussed in detail in this preamble, in the preamble for the January 2014 proposal, and in associated technical support documents, the power sector has moved toward increased use of natural gas for a variety of reasons. If capital was the only cost that utilities and project developers considered, then they would almost certainly always choose to build a new NGCC unit. However, a variety of factors can be involved in selecting a generation source beyond capital costs. Accordingly, in considering cost reasonableness the EPA considered metrics that encompassed other costs as well as the value of fuel and fleet diversity.

Some commenters maintained that even if LCOE was a proper cost metric, the comparison with the costs of a new nuclear power plant is improper because nuclear itself is a highly expensive technology. The EPA disagrees. The comparison is appropriate and valid because, as discussed at V.H.3 above, under current and foreseeable economic conditions affecting the cost of new fossil steam generation and new nuclear generation relative to the cost of new natural gas generation, neither new nuclear power nor fossil steam generation are competitive with new natural gas if evaluated on the basis of LCOE alone. Nonetheless, both are important potential alternatives to natural gas power for those interested in dispatchable base load power that maintains or increases fuel diversity. As shown in a survey of recent IRP filings in the docket[302] and Section II.C.5 above, several utilities are considering new nuclear power as a potential generation option. Because both fossil steam and nuclear generation serve a comparable role of offering a diverse source of base load power generation, the EPA concludes that the comparison of their LCOE is a valid approach to evaluating cost reasonableness.

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[299] Tracking Clean Energy Progress 2013, International Energy Agency (IEA), Input to the Clean Energy Ministerial, OECD/IEA 2013.

[300] Comments of EEI, pp 94–5 (Docket entry: EPA–HQ–OAR–2013–0495–9780).

[301] *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[302] Technical Support Document—''Review of Electric Utility Integrated Resource Plans'' (May 2015), available in the rulemaking docket EPA–HQ–OAR–2013–0495.

2. Use of Cost Estimates From DOE/NETL and DOE/EIA

In the January 2014 proposal, the EPA relied mostly on the cost projections for new fossil fuel-fired generating sources that were informed by cost studies conducted by DOE/NETL. The EPA relied on the EIA's AEO 2013 projections for non-fossil based generating sources (*i.e.,* nuclear, renewables, etc.). For this final rule, the EPA continues to rely most heavily on DOE/NETL cost projections for fossil fuel generating technologies and on the updated DOE/EIA AEO 2014 for nuclear and other base load non-fossil generation technologies.

a. DOE/NETL Cost and Performance Studies

The DOE/NETL ''Cost and Performance Baselines for Fossil Energy Plants'' are a series of studies conducted by NETL to establish estimates for the cost and performance of combustion and gasification based power plants with and without CO_2 capture and storage.[303] The studies evaluate numerous technology configurations utilizing different coal ranks and natural gas.

The EPA relied on those sources because the NETL studies are the most comprehensive and transparent of the available cost studies and NETL has a reputation in the power sector industry for producing high quality, reliable work.[304] The NETL studies were extensively peer reviewed.[305] The EPA Science Advisory Board Work Group considering the adequacy of the peer review noted the EPA staff's statement that ''the NETL studies were all peer reviewed under DOE peer review protocols'', further noted the EPA staff's statement that ''the different levels of review of these DOE documents met the requirements to support the analyses as defined by the EPA Peer Review Handbook,'' and concluded that ''peer review on the DOE documents'' was conducted ''at a level required by agency guidance.'' [306]

The cost estimates were indicated by DOE/NETL to carry an accuracy of −15 percent to +30 percent on the capital costs, consistent with a AACE Class 4 cost estimate—*i.e.,* a ''feasibility study'' level of design engineering.[307] The DOE/NETL further notes that ''The value of the study lies not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.'' [308]

For the final standard, the EPA made particular use of the most recent NETL cost estimates for post-combustion CCS, which reflect up-to-date vendor quotes and incorporate the post-combustion capture technology—the Shell Cansolv amine-based process—that is being utilized at the Boundary Dam Unit #3 facility.[309] The EPA used this latest version of the NETL studies not only to assure that it considers the most up-to-date information but also to address public comments criticizing the proposal for relying on out-of-date cost information.

b. Other Studies That Corroborate NETL Cost Estimates

A variety of government, industry and academic groups routinely conduct studies to estimate costs of new generating technologies. These studies use techno-economic models to predict the cost to build a new generating facility at some point in the future. These studies often use levelized cost of electricity (LCOE) to summarize costs and to compare the competiveness of the different generating technologies.

A variety of groups have recently published LCOE estimates for new dispatchable generating technologies. Those are shown below in Table 10. The table shows LCOE projections from the EPA's January 2014 proposal, from studies conducted by the Electric Power Research Institute (EPRI),[310] by the DOE's Energy Information Administration (EIA) in their 2015 Annual Energy Outlook (AEO 2015), by the DOE's National Energy Technology Laboratory (NETL), and by researchers from the Department of Engineering and Public Policy at the Carnegie Mellon University (CMU) in Pittsburgh, PA.

The Global CCS Institute [311] has recently published a report that examines costs of major low and zero emissions technologies currently available for power generation and compares the predicted LCOEs of those technologies. Importantly, the analysis presented in the report uses cost and performance data from several recent studies, and applies a common methodology and economic parameters to derive comparable lifetime costs. Analysis and findings in the paper reflect costs specific to the U.S.

The fact that these various groups have conducted independent studies and that the results of those independent studies are reasonably consistent with the estimates of DOE/NETL are further indications that the DOE/NETL cost estimates are reasonable.

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[303] *http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.*

[304] The NETL costs and studies are often cited in academic and other publications.

[305] The initial NETL study ''Cost and Performance Baseline for Fossil Energy Plants, Vol. 1: Bituminous Coal and Natural Gas to Electricity'' (2006) was subject to peer review by industry experts, academia, and government research and regulatory agencies. Subsequent iterations of the study were not further peer reviewed because the modeling procedures used in the cost estimation were not revised.

[306] Letter from James Mihelcic, Chair, SAB Work Group on EPA Planned Actions for SAB Consideration of the Underlying Science to Members of the Chartered SAB and SAB Liaisons (page 3, Jan. 24, 2014). *http://yosemite.epa.gov/sab/sabproduct.nsf/F43D89070E89893485257C5A007AF573/$File/SAB+work+grp+memo+w+attach+20140107.pdf.* The SAB's statement that these guidance documents ''require'' any specific peer review is an overstatement, since guidance documents, by definition, do not mandate any specific course of action.

[307] Recommended Practice 18R–97 of the Association for the Advancement of Cost Engineering International (AACE) describes a Cost Estimate Classification System as applied in Engineering, Procurement and Construction for the process industries.

[308] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'' Rev 2a (Sept 2013); DOE/NETL–2010/1397, page 9.

[309] Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3, July 6, 2015, DOE/NETL–2015/1723.

[310] EPRI is a non-profit organization, headquartered in Palo Alto, CA, that conducts research on issues related to the U.S. electric power industry (*www.epri.com*).

[311] *www.globalccsinstitute.com.*

TABLE 10—SELECTION OF LEVELIZED COST OF ELECTRICITY (LCOE) PROJECTIONS

New generation technology	Lazard [312] $2014/MWh	EPRI [313] $2011/MWh	AEO2015 [314] $2013/MWh*	DOE/NETL [315] $2011/MWh*	CMU [316] $2010/MWh	GCCSI [317]** $2014/MWh
SCPC—no CCS	66	62–77	95	76–95	59	78
SCPC—full CCS	151	102–137	—	140–176	—	115–160
SCPC—16% CCS	—	—	—	92–117	—	—
Nuclear***	92–132	85–97	87–115	—	—	86–102
Biomass	87–116	90–155	94–113	—	—	123–137
IGCC	102	82–96	116	94–120	—	—
IGCC—full CCS	171	105–136	144	142–178	—	—
NGCC	61—87	33—65	73	58	63	60

* EIA, in cost projections for SCPC and IGCC with no CCS, includes a climate uncertainty adder (CUA), which is a 3-percentage point increase in the cost of capital. In contrast, DOE/NETL utilized conventional financing for cases without CCS and utilized high-risk financial assumptions for cases that include CCS.

** The Global CCS Institute provided range for coal with full CCS (shown as ''CCS(coal)'' in Figure 5.2 of the referenced report) reflects a combination of costs for both PC and IGCC coal plants.

*** EIA AEO assumes use of Westinghouse AP1000 technology. Other groups assume a wider range of technology options.

The LCOE values from the Lazard, EPRI, and NETL studies are presented as a range. The EPRI costs incorporate uncertainty reflecting the range of inputs (*i.e.,* capital costs, fuel costs, fixed and variable O&M, etc.). The NETL costs are indicated to carry an accuracy of − 15 percent to + 30 percent, consistent with a ''feasibility study'' level of design. The range in Table 10 is the NETL projected costs with the − 15 percent to +30 percent uncertainty on the capital costs. Overall, as can be seen from the results in Table 10, the range of LCOE estimates from the different groups are in reasonable agreement with the DOE/NETL estimates most often representing the most conservative of the estimates shown.

The EIA cost estimates include a climate uncertainty adder (CUA)—represented by a three percent increase to the weighted average cost of capital—to certain coal-fired capacity types. The EIA developed the CUA to address inconsistencies between power sector modeling absent GHG regulation and the widespread use of a cost of CO_2 emissions in power sector resource planning. The CUA reflects the additional planning cost typically assigned by project developers and utilities to GHG-intensive projects in a context of climate uncertainty. The EPA believes the CUA is consistent with the industry's planning and evaluation framework (demonstrable through IRPs and PUC orders) and is therefore pertinent when evaluating the cost competitiveness of alternative generating technologies. The EPA believes the CUA is relevant in considering the range of costs that power companies are willing to pay for generation alternatives to natural gas.

c. Industry Information That Corroborates NETL Cost Estimates

Information from vendors of CCS technology also supports the reliability of the cost estimates the EPA is using here.[318] Specifically, the EPA had conversations with representatives from Summit Carbon Capture, LLC regarding available cost information. Cost estimates provided by another leading provider of CCS technology likewise are consistent (indeed, somewhat less than) the estimates the EPA is using for purposes of cost analysis in the rule.

Summit Carbon Capture's primary business is large-scale carbon capture from power and other industrial projects and use of the captured CO_2 for EOR.[319] Summit is actively working with several different technology companies offering CO_2 capture systems, including the leading equipment manufacturers for fossil fuel power production equipment. Their current projects include the 400 MW IGCC Texas Clean Energy Project and the Caledonia Clean Energy Project—a new project underway in the United Kingdom—and a variety of other projects under development which are not yet public.

Summit is also interested in potentially retrofitting CCS onto existing coal-fired plants for the purpose of capturing CO_2 for sale to EOR markets. Summit provided the EPA with copies of slides from a presentation that it has used in different public forums.[320] The presentation focused on costs to retrofit available carbon capture equipment at an existing PC power plant that is ideally located to take advantage of opportunities to sell captured CO_2 for use in EOR operations. Summit received proprietary costing information from numerous technology providers and that information, along with other publically available information, was used to develop their cost predictions.[321] Though the primary focus of their effort was to examine costs associated with retrofitting CCS to an existing coal fired power plant, Summit Power also calculated costs for several new generation scenarios—including the cost of a new NGCC, a new SCPC, a new SCPC with full CCS, and a new SCPC with partial CCS at 50 percent. The costs are reasonably consistent with costs predicted by NETL, EIA, EPRI and others. The company ultimately concluded that ''in a world of uncertain gas prices, falling CO_2 capture

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[312] Lazard's Levelized Cost of Energy Analysis—Version 8.0 (Sept 2014); available at *http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf* and in the rulemaking docket.

[313] ''Program on Technology Innovation: Integrated Generation Technology Options 2012; Report 1026656; Available at: *www.epri.com.*

[314] ''Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015'', Available at: *www.eia.gov/forecasts/aeo/electricity_generation.cfm*; the LCOE values displayed incorporate −10%/+30% for uncertainty for biomass and nuclear.

[315] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'' DOE/NETL–2015/1720 (June 22, 2015).

[316] CMU is Carnegie Mellon University; Zhai, H., Rubin, E.; ''Comparative Performance and Cost Assessments of Coal- and Natural Gas-Fired Power Plants under a CO_2 Emission Performance Standard Regulation'', *Energy & Fuels,* 2013, 27, 4290, Table 1.

[317] ''The Costs of CCS and other Low-Carbon Technologies—2015 update'' July 2015, Global CCS Institute, Available at: *http://hub.globalccsinstitute.com/sites/default/files/publications/195008/costs-ccs-other-low-carbon-technologies-2015-update.pdf.*

[318] See Section V.F above, explaining that the D.C. Circuit has repeatedly stated that vendor statements are probative in demonstrating that a technology is adequately demonstrated under section 111.

[319] *http://www.summitpower.com/projects/carbon-capture/.*

[320] ''Coal's Role in a Low Carbon Energy Environment'', presented at 2015 Euromoney Power & Renewables Conference, remarks by Jeffrey Brown (amended to address EPA questions on the original). Available in the rulemaking docket.

[321] No proprietary or business confidential information was shared with the EPA. No specific vendors were mentioned by name during discussions with Summit Power. Summit also used available DOE/NETL and EIA cost information.

equipment prices, improving CCS process efficiency, and possible compliance costs . . . existing coal plants retrofitted with available CCS equipment can be cost competitive with development of new NGCC generation.’’ [322]

In June 2012, Alstom Power released a report entitled ‘‘Cost assessment of fossil power plants equipped with CCS under typical scenarios’’.[323] The study examined costs for a new coal-fired power plant implementing post-combustion CCS (full CCS) in Europe, in North America, and in Asia. The results for the North American case—along with similar cost estimates from Summit—are shown in Table 11 below. The DOE/NETL estimated costs are also included for comparison. The results show predicted costs for a new SCPC ranging from $53/MWh to $82/MWh and costs to implement full CCS ranging from $97/MWh to $143/MWh. Costs to implement varying levels of partial CCS are also provided for comparison. The industry cost estimates are on the lower end of the range of costs predicted from other techno-economic studies (see Table 11 below) and, like those economic studies, are affected by the specific assumptions. As with the techo-economic studies presented earlier in Table 10, there is relatively good agreement among these projected costs and the DOE/NETL costs. There is relatively good agreement in the incremental levelized cost to implement full CCS on the new SCPC units (ranging from 74 to 85 percent) and to implement 50 percent CCS on the new SCPC unit (from 41 to 45 percent increase). These industry estimates are also lower than the DOE/NETL estimates for both full and 50 percent partial CCS (with the incremental cost percentage for full CCS being almost identical), providing further support for the reasonableness of the EPA using the NETL cost estimates here.

TABLE 11—INDUSTRY LCOE ESTIMATES FOR IMPLEMENTATION OF POST-COMBUSTION CCS [324]

	Summit $/MWh	Alstom $/MWh*	DOE/NETL $/MWh
SCPC	64.5	52.6	82.3
SCPC + full CCS	117.6	97.4	152.4
Full CCS incremental cost, %	82.3%	85.0%	85.2%
SCPC + 50% CCS	91.1	—	123.6
50% CCS incremental cost, %	41.2%	—	50.1%
SCPC + 35% CCS	—	—	114.7
SCPC + 16% CCS	—	—	100.5
NGCC**	47.7	35.0	**52.0

* Costs are from Figure 2 in the referenced Alstom report (North American case); costs are presented as €/MWh in the report. The costs were converted to $/MWh assuming a conversion rate of 1 USD = 0.76 € (in 2012).

** NGCC cost is estimated by the EPA using NETL information. Assumed natural gas prices = Summit ($4/mmBtu); Astom ($3.9/mmBtu); EPA ($5.00/mmBtu).

The EPA notes that in its public comments, Alstom maintained that ‘‘no CCS projects that would [sic] be considered cost competitive in today’s energy economy.’’ [325] As explained above, no steam electric EGU would be cost competitive even without CCS—and that is substantiated in the projected costs presented above in Table 11 where NGCC is consistently the most economic new generation option when compared to the other listed technologies. Alstom does not explain (or address) why the cost premium for partial CCS would be a decisive deterrent for capacity that would otherwise be constructed. More important, Alstom does not challenge the specific cost estimates used by the EPA at proposal, nor disavow its own estimates of CCS costs (which are even less) which it is publically disseminating in the marketplace. See also Section V.F.3 above, quoting Alstom’s press release stating unequivocally that ‘‘CCS works and is cost-effective’’. The EPA reasonably is relying on the specific Alstom estimates which it is using for its own commercial purposes, and not on the generalized concerns presented in its public comments.

d. Use of Cost Information From EIA Annual Energy Outlook (AEO)

For the January 2014 proposal the EPA chose to rely on the EIA AEO 2013 cost projections for non-fossil based generation. The AEO presents long-term annual projections of energy supply, demand, and prices focused on U.S. energy markets. The predictions are based on results from EIA’s National Energy Modeling System (NEMS). The AEO costs are updated annually, they are highly scrutinized, and they are widely used by those involved in the energy sector.

In the January 2014 proposal, the EPA presented LCOE costs for new non-fossil dispatchable generation (see 77 FR 1477, Table 7) from the AEO 2013. Those costs were updated as part of the AEO 2015 release. The estimated cost for all of these technologies decreased from AEO 2013 to AEO 2014 and AEO 2015. This was due to changes in the interest rates that resulted in lower financing costs relative to those used the AEO 2013.[326] The EIA commissioned a comprehensive update of its capital cost assumptions for all generation technologies in 2013. Fuel cost and

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[322] Others have come to similar conclusions—that retrofit of CCS technology at existing coal-fired power plants can be feasible—*e.g.,* ‘‘The results indicate that for about 60 gigawatts of the existing coal-fired capacity, the implementation of partial CO_2 capture appears feasible, though its cost is highly dependent on the unit characteristics and fuel prices.’’ (Zhai, H.; Ou, Y.; Rubin, E.S.; ‘‘Opportunities for Decarbonizing Existing U.S. Coal-fired Plants via CO_2 Capture, Utilization, and Storage’’, accepted for publication in *Env. Sci & Tech.* (2015).

[323] Leandri, J., Skea, A., Bohtz, C., Heinz, G.; ‘‘Cost assessment of fossil power plants equipped with CCS under typical scenarios’’, Alstom Power, June 2012. Available in the rulemaking docket: EPA–HQ–OAR–2013–0495.

[324] Note that in other tables in this preamble, the EPA has presented LCOE values from the DOE/NETL work as a range in order to incorporate the uncertainty on the capital costs. The range is not present here for easy comparison with the industry costs which were not provided as a range. The full range of DOE/NETL costs for each of the cases presented can be found in Exhibit A–3 in ‘‘Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants’’, DOE/NETL–2015/1720 (June 2015), p. 18.

[325] Alstom Comment p. 3 (Docket entry: EPA–HQ–OAR–2013–0495–9033). The comment also urged the EPA to evaluate costs without considering EOR opportunities (which in fact is our methodology, albeit a conservative one), and without considering possible subsidies. Id. The LCOE and capital cost estimates above are direct cost comparisons, again consistent with the commenter’s position.

[326] *www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf.*

financial assumptions are updated for each edition of the Annual Energy Outlook.

e. Accounting for Uncertainty of Projected Costs

As previously mentioned, the projected costs are dependent upon a range of assumptions including the projected capital costs, the cost of financing the project, the fixed and variable O&M costs, the projected fuel costs, and incorporation of any incentives such as tax credits or favorable financing that may be available to the project developer. There are also regional or geographic differences that affect the final cost of a project. The LCOE projections in this final action are not intended to provide an absolute cost for a new project using any of these respective technologies. Large construction projects—as these would be—would be subjected to detailed cost analyses that would take into consideration site-specific information and specific design details in order to determine the project costs.

The DOE/NETL noted that the cost estimates from their studies carry an accuracy in the range of −15 percent to +30 percent, which is consistent with a ''feasibility study'' level of design. They also noted that the value of the studies lies ''not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.''

The EIA AEO 2015 presented LCOE costs as a single point estimate representing average nationwide costs and separately as a range to represent the regional variation in costs. In order to compare the fossil fuel generation technologies from the NETL studies with the cost projections for non-fossil dispatchable technologies from EIA AEO 2015, we assume that the EIA studies would carry a similar level of uncertainty (*i.e.,* +30 percent) and we present the AEO 2015 projected costs as the average nationwide LCOE with a range of −10 percent to +30 percent to account for uncertainty.[327] The EIA does not provide uncertainty estimates in the AEO cost projections. However, nuclear experts from EIA staff have indicated to the EPA that a range of uncertainty of −10 percent to +30 percent on the capital component of the LCOE can be expected based on market uncertainties. Specifically, these staff experts expect that nuclear plants currently under construction would not have capital costs under estimates and that one could expect to see a 30 percent ''upside'' variation in capital cost. There is also insufficient market data to get a good statistical range of potential capital cost variation (*i.e.,* only two plants under construction, neither complete). This is reasonably consistent with estimates for nuclear costs estimated by Lazard (see Table 8 above) which likewise reflect a similar level of cost uncertainty. The Lazard nuclear costs show a range of projected levelized capital cost from $73/MWh to $110/MWh—a range of 50 percent, very similar to the 40 percent range (*i.e.,* −10 percent to +30 percent) suggested by EIA nuclear experts. The Global CCS Institute, in its most recent cost update, also provides nuclear costs as a range from $86/MWh to $102/MWh.[328]

3. Use of Costs From Current Projects

Although we are relying on cost estimates drawn from techno-economic models, we recognize that there are a few steam electric plants that include CCS that have been built, or are being constructed. Some information about the costs (or cost-to-date) for these projects is known. We discuss in this section the costs at facilities which have installed or are installing CCS, why the EPA does not consider those costs to be reasonably predictive of the costs of the next new plants to be built, and why the EPA considers that the next new plants will have lower costs along the lines predicted by NETL.[329]

The Boundary Dam Unit #3 facility utilizing post-combustion capture from Shell Cansolv is now operational. Petra Nova, a joint venture between NRG Energy Inc. and JX Nippon Oil & Gas Exploration, is currently constructing a post-combustion capture system at NRG's WA Parish generating station near Houston, TX. The post-combustion capture system will utilize MHI amine-based solvents and is currently being constructed with plans to initiate operation in 2016.[330]

Construction on Mississippi Power's Kemper County Energy Center IGCC facility is now nearly complete. The combined cycle portion of the facility has been generating power using natural gas. The gasification portion of the facility and the carbon capture system are undergoing system checks and training to enable commercial operations using a UOP Selexol™ pre-combustion capture system in early 2016.[331]

Another full-scale project, the Summit Power Texas Clean Energy Project has not commenced construction but remains a viable project. Several other full-scale projects have been proposed and have progressed through the early stages of design, but have been cancelled or postponed for a variety of reasons.

Some cost information is also available for small demonstration projects—including those that have been supported by USDOE research programs. These projects would include Alabama Power's demonstration project at Plant Barry and the AEP/Alstom demonstration at Plant Mountaineer.

Many commenters felt that the EPA should rely on those high costs when considering whether the costs are reasonable. The costs from these large-scale projects appear to be consistently higher than those projected by techno-economic models. However, the costs from these full-scale projects represent first-of-a-kind (FOAK) costs and, it is reasonable to expect these costs to come down to the level projected in the NETL and other techno-economic studies for the next new projects that are built—which are the sources that would be subject to this standard.

Significant reductions in the cost of CO_2 capture would be consistent with overall experience with the cost of pollution control technology. A significant body of literature suggests

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[327] EIA does not provided uncertainty estimates in the AEO cost projections. However, EIA staff have indicated to the EPA that a range of uncertainty of −10%/+30% on the capital component of the LCOE can be expected based on market uncertainties. See memorandum ''Range of uncertainty for AEO nuclear costs'' available in the rulemaking docket, EPA–HQ–OAR–2013–0495.

[328] ''The Costs of CCS and other Low-Carbon Technologies—2015 update'' July 2015, Global CCS Institute, Available at: *http://hub.globalccsinstitute.com/sites/default/files/publications/195008/costs-ccs-other-low-carbon-technologies-2015-update.pdf.*

[329] The EPA notes that two of these facilities, Kemper and TCEP, received both assistance from DOE under EPAct05 and the IRC section 48A tax credit; and that the AEP Mountaineer pilot project received assistance from DOE under EPAct05. Under the most extreme interpretations of those provisions offered by commenters, the EPA would be precluded from any consideration of any information from those sources, including cost information, in showing whether a system of emission reduction is adequately demonstrated. We note, however, that many of these same commenters urged consideration of the cost information from these sources. In fact, the EPA is not relying on information about the costs of these sources to determine the BSER or the standards of performance in this rulemaking, and the EPA is discussing the cost information here to explain why not. Accordingly, this discussion of cost information from these sources is not precluded by the EPAct05 and IRC section 48A provisions and, even if it is precluded, that would have no impact on the EPA's determination of the BSER and the standards of performance in this rule.

[330] *http://www.nrg.com/sustainability/strategy/enhance-generation/carbon-capture/wa-parish-ccs-project/.*

[331] *http://www.mississippipower.com/about-energy/plants/kemper-county-energy-facility/facts.*

that the per-unit cost of producing or using a given technology declines as experience with that technology increases over time, and this has certainly been the case with air pollution control technologies. Reductions in the cost of air pollution control technologies as a result of learning-by-doing, research and development investments, and other factors have been observed over the decades. We expect that the costs of capture technology will follow this pattern.

The NETL cost estimates reasonably account for this documented phenomenon. Specifically, ''[I]n all cases, the report intends to represent the next commercial offering, and relies on vendor cost estimates for component technologies. It also applies process contingencies at the appropriate subsystem levels in an attempt to account for expected but undefined costs (a challenge for emerging technologies).'' [332]

Commenters argued that the next plants to be built would still reflect first-of-a-kind costs, pointing to the newness of the technology and the lack of operating experience, *i.e.* the alleged absence of learning by doing. The EPA disagrees. In addition to operating experience from operating and partially constructed CCS projects, substantial research efforts are underway providing a further knowledge base to reduce CO_2 capture costs and to improve performance.

The DOE/NETL sponsors an extensive research, development and demonstration program that is focused on developing advanced technology options that will dramatically lower the cost of capturing CO_2 from fossil fuel energy plants compared to currently available capture technologies. The large-scale CO_2 capture demonstrations that are currently planned and in some cases underway, under DOE's initiatives, as well as other domestic and international projects, will generate operational knowledge and enable continued commercialization and deployment of these technologies. Gas absorption processes using chemical solvents, such as amines, to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry and to produce food and chemical grade CO_2. The advancement of amine-based solvents is an example of technology development that has improved the cost and performance of CO_2 capture. Most single component amine systems are not practical in a flue gas environment as the amine will rapidly degrade in the presence of oxygen and other contaminants. The Fluor Econamine FG process, the process modeled in the NETL cost study for the SCPC cases, uses a monoethanolamine (MEA) formulation specially designed to recover CO_2 and contains a corrosion inhibitor that allows the use of less expensive, conventional materials of construction. Other commercially available processes use sterically hindered amine formulations (for example, the Mitsubishi Heavy Industries KS–1 solvent) which are less susceptible to degradation and corrosion issues.

The DOE/NETL and private industry are continuing to sponsor research on advanced solvents (including new classes of amines) to improve the CO_2 capture performance and reduce costs.

As noted in Section V.H.7.d above, SaskPower has created the CCS Global Consortium to facilitate further knowledge regarding, and use of, carbon capture technology.[333] This consortium provides SaskPower the opportunity to share its knowledge and experience with global energy leaders, technology developers, and project developers. SaskPower, in partnership with Mitsubishi and Hitachi, is also helping to advance CCS knowledge and technology through the creation of the Shand Carbon Capture Test Facility (CCTF).[334] The test facility will provide technology developers with an opportunity to test new and emerging carbon capture systems for controlling carbon emissions from coal-fired power plants.

We also note certain features of the commercial plants already built that suggest that their costs are uniquely high, and otherwise not fairly comparable to the costs of plants meeting the NSPS using the BSER. Most obviously, many of these projects involve deeper capture than the partial CCS that the EPA assumes in this final action. In addition, cost overruns at the Kemper facility, mentioned repeatedly in the public comments, resulted in major part from highly idiosyncratic circumstances, and are related to the cost of the IGCC system, not to the cost of CCS.[335] The EPA does not believe that these unusual circumstances are a reasonable basis for assessing costs of either CCS or IGCC here.

4. Cost Competitiveness of New Coal Units

As the EPA noted, all indications suggest that very few new coal-fired power plants will be constructed in the foreseeable future. Although a small number of new coal-fired power plants have been built recently, the industry generally is not building these kinds of power plants at present and is not expected to do so for the foreseeable future. The reasons include the current economic environment and improved energy efficiency, which has led to lower electricity demand, and competitive current and projected natural gas prices. On average, the cost of generation from a new NGCC power plant is expected to be lower than the cost of generation from a new coal-fired power plant, and the EPA has concluded that, even in the absence of the requirements of this final rule, very few new coal-fired power plants will be built in the near term.

Some commenters, however, disagreed with this conclusion. They contended instead that it is the CCS-based NSPS that would preclude such new generation. However, as the EPA has discussed, there is considerable evidence that utilities and project developers are moving away—or have already moved away—from a long term dependence on coal-fired generating sources. A review of publicly available integrated resource plans show that many utilities are not considering construction of new coal-fired sources without CCS. See Section V. H.3 above. Few new coal-fired generating sources have commenced construction in the past 5 years and, of the projects that are currently in the development phase, the EPA is only aware of projects that will include CCS in the design. As we have noted in this preamble, the bulk of new

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[332] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3'', DOE/NETL–2015/1723 (July 2015) at p. 38.

[333] *http://www.saskpowerccs.com/consortium/*.

[334] *http://www.saskpowerccs.com/ccs-projects/shand-carbon-capture-test-facility/*.

[335] See Independent Monitor's Prudency Evaluation Report for the Kemper County IGCC Project (prepared for Mississippi Public Utilities Staff), available at *www.psc.state.ms.us/InsiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=328417* (''Report''). As documented in this Report, costs escalated significantly because the developers adopted a ''compressed schedule'' in an attempt to obtain the IRC 48A tax credit, resulting in ''engineering and design changes which are a normal result of detailed engineering and design . . . occurring at the same time as, rather than ahead of, construction activities'', which did not allow for proper sequencing during construction. This '' 'just-in-time' approach to engineering and procurement (meaning that the engineering was often completed shortly before material procurement and construction activities) resulted in a greater number of construction work-arounds, congestion of construction craft labor in the field, inefficiencies and additional steps that became necessary during construction to cope with this just-in-time engineering, procurement and construction approach.'' Report, p. 6. Ironically, work was still completed too late to obtain the tax credit. Id. p. 15.

generation that has been added recently has been either natural gas-fired or renewable sources. Overall, the EPA remains convinced that the energy sector modeling is reflecting the realities of the market in predicting very few new coal-fired power plants in the near future—even in the absence of these final standards.

In addition, we note that the Administration's CCS Task Force report recognized that CCS would not become more widely available without the advent of a regulatory framework that promoted CCS or provided a strong price signal for CO_2. In this regard, we note American Electric Power's statements regarding the need for federal requirement for GHG control to aid in cost recovery for CCS projects, to attract other investment partners, and thereby promote advancement and deployment of CCS technology: ''as a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund the industry's share''.[336] Indeed, AEP has stated that CCS is important for the very future of the industry: ''AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation.'' [337] This final rule's action is an important component in developing that needed regulatory framework.

5. Accuracy of Cost Estimates for Transportation and Geologic Sequestration

The EPA's estimates of costs take into account the transport of CO_2 and sequestration of captured CO_2. Estimates of transport and sequestration costs—approximately $5–$15 per ton of CO_2—are based on DOE NETL studies and are also consistent with other published studies.[338] For transport, costs reflect pipeline capital costs, related capital expenditures, and O&M costs. Sequestration cost estimates reflect the cost of site screening and evaluation, the cost of injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long term liability protection. These sequestration costs reflect the regulatory requirements of the Underground Injection Control Class VI program and GHGRP subpart RR for geologic sequestration of CO_2 in deep saline formations, which are discussed further in Sections V. M. and N below.[339]

Based on DOE/NETL studies, the EPA estimated that the total CO_2 transportation, storage, and monitoring (TSM) cost associated with EGU CCS would comprise less than 5.5 percent of the total cost of electricity in all capture cases modeled—approximately $5–$15 per ton of CO_2.[340] The range of TSM costs the EPA relied on are broadly consistent with estimates provided by the Global Carbon Capture and Storage Institute as well.[341] Some commenters suggested that the EPA underestimated the costs associated with transporting captured CO_2 from an EGU to a sequestration site.[342] Specifically, commenters suggested that the EPA's estimated costs for constructing pipelines were lower than costs based on actual industry experience. Commenters also opined that the EPA's assumed length of pipeline needed between the EGU and the sequestration site is not reasonable and that the DOE/NETL study upon which the EPA relied does not account for CO_2 transport costs when EOR is not available.

The EPA believes its estimates of transportation and sequestration costs are reasonable. First, the EPA in fact includes cost estimates for CO_2 transport when EOR opportunities are not available—consistent with its overall conservative cost methodology of assuming no revenues from sale of captured CO_2. Specifically, the EPA estimates transport, storage and monitoring (TSM) costs of $5–$15 per ton of CO_2 for non-EOR applications.[343] This estimate is reflected in the LCOE comparative costs.[344]

The EPA also carefully reviewed the assumptions on which the transport cost estimates are based and continues to find them reasonable. The NETL studies referenced in Section V.I.2 above based transport costs on a generic 100 km (62 mi) pipeline and a generic 80 kilometer pipeline.[345] At least one study estimated that of the 500 largest point sources of CO_2 in the United States, 95 percent are within 50 miles of a potential storage reservoir.[346] As a point of reference, the longest CO_2 pipeline in the United States is 502 miles.[347] For new sources, pipeline distance and costs can be factored into siting and, as discussed in Section V.M, there is widespread availability of geologic formations for geologic sequestration (GS). Moreover, data from the Pipeline and Hazardous Materials Safety Administration show that in 2013 there were 5,195 miles of CO_2 pipelines operating in the United States. This represents a seven percent increase in CO_2 pipeline miles over the previous year and a 38 percent increase in CO_2 pipeline miles since 2004. For the reasons outlined above, the EPA believes its estimates have a reasoned basis. See also Section V.M below further discussing the current availability of CO_2 pipelines.

With respect to sequestration, certain commenters argued that the EPA's cost analysis failed to account for many contingencies and uncertainties (surface and sub-surface property rights in particular), ignored the costs of GHGRP subpart RR, and also was not representative of the costs associated with specific GS site characterization, development, and operation/injection of monitoring wells. Commenter American Electric Power (AEP) referred to its own

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[336] *www.aep.com/newsroom/newsreleases/?id=1704.*

[337] ''CCS LESSONS LEARNED REPORT American Electric Power Mountaineer CCS II Project Phase 1'', prepared for The Global CCS Institute Project # PRO 004, January 23, 2012, page 2. Available at: *www.globalccsinstitute.com/publications/ccs-lessons-learned-report-american-electric-power-mountaineer-ccs-ii-project-phase-1*; See also AEP FEED Study at pp. 4, 63, Available at: *www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report.*

[338] *Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases* (DOE/NETL–341/082312); *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture* (DOE/NETL–2011/1498); *Cost and Performance Baseline for Fossil Energy Plants* (DOE/NETL–2010/1397); *Economic Evaluation of* CO_2 *Storage and Sink Enhancement Options, Tennessee Valley Authority, NETL and EPRI, December 2002; Carbon Dioxide and Transport and Storage Costs in NETL Studies* (DOE/NETL–2013/1614), March 2013; *Carbon Dioxide and Transport and Storage Costs in NETL Studies* (DOE/NETL–2014/1653), May 2014; *Cost and Performance Baseline for Fossil Energy Power Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity* (DOE–NETL–2015/1723), July 2015.

[339] Carbon Dioxide and Transport and Storage Costs in NETL Studies. DOE/NETL–2013/1614. March 2013. P. 13.

[340] RIA at section 5.5; proposed rule RIA at 5–30.

[341] *http://hub.globalccsinstitute.com/sites/default/files/publications/12786/economic-assessment-carbon-capture-and-storage-technologies-2011-update.pdf.*

[342] See, for example, comments from American Electric Power, pp 97–8 (Docket entry: EPA–HQ–OAR–2013–0495–10618), Southern Company, pp. 47–48 (Docket entry: EPA–HQ–OAR–2013–0495–10095), and Duke Energy p. 28 (Docket entry: EPA–HQ–OAR–2013–0495–9426).

[343] See RIA at section 5.5 and proposed RIA at 5–30.

[344] See RIA at section 5.5.

[345] The pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length.

[346] JJ Dooley, CL Davidson, RT Dahowski, MA Wise, N Gupta, SH Kim, EL Malone (2006), Carbon Dioxide Capture and Geologic Storage: A Key Component of a Global Energy Technology Strategy to Address Climate Change. Joint Global Change Research Institute, Battelle Pacific Northwest Division. PNWD–3602. College Park, MD.

[347] A Review of the CO_2 Pipeline Infrastructure in the U.S., April 21, 2015, DOE/NETL–2014/1681, Office of Fossil Energy, National Energy Technology Laboratory.

experience with the Mountaineer demonstration project. AEP noted that although this project was not full scale, finding a suitable repository, notwithstanding a generally favorable geologic area, proved difficult. The company referred to its estimated cost of expanding the existing Mountaineer plant to a larger scale project, particularly the cost of site characterization and well construction.[348]

The EPA's cost estimates account for the requirements of the Underground Injection Control Class VI program, and GHGRP subpart RR, among them site screening and evaluation costs, costs for injection wells and equipment, O&M costs, and monitoring costs. The estimated sequestration costs include operational and post-injection site care monitoring, which are components of the UIC Class VI requirements, and also reflect costs for sub-surface pore volume property rights acquisition.[349] These estimates are consistent with the costs presented in the study *CO_2 Storage and Sink Enhancements: Developing Comparable Economics,* which incorporates the costs associated with site evaluation, well drilling, and the capital equipment required for transporting and injecting CO_2.[350] [351] Monitoring costs were evaluated based on the methodology set forth in the International Energy Agency Greenhouse Gas R&D Programme's *Overview of Monitoring Projects for Geologic Storage Projects* report.[352]

The EPA's cost estimates for sequestration thus cover all aspects commenters claimed the EPA disregarded. The EPA believes that the use of costs and scenarios presented in the studies referenced are representative for purposes of the cost analysis. The NETL cost estimates upon which the EPA's costs draw directly from the UIC Class VI economic impact analysis.[353] That analysis is based on estimated characteristics for a representative group of projects over a 50-year period of analysis, as well as industry averages for several cost components and sub-components. The EPA also made reasonable assumptions regarding the assumed injection site: A deep saline formation with typical characteristics (*e.g.,* representative depth and pressure).[354]

With respect to AEP's experience with the Mountaineer demonstration project, sequestration siting issues are of course site-specific, and raise individual issues. For this reason, it is inappropriate to generalize from a particular individual experience. In this regard, as explained in Section V.N below, the construction permits issued by the EPA to-date under the Underground Injection Control Class VI regulations required far fewer wells for site characterization and monitoring than AEP found to be necessary at its Mountaineer site. Moreover, notwithstanding difficulties, the company was able to successfully drill and complete wells, and safely inject captured CO_2. The company also indicated it fully expected to be able to do so at full scale and explained how.[355] For discussion of 40 CFR part 98, subpart RR (the GHGRP requirements for geologic sequestration), including costs associated with compliance with those requirements, see Section V.N below.

J. Achievability of the Final Standards

The EPA finds the final standard of 1,400 lb CO_2/MWh-g to be achievable over a wide range of variable conditions that are reasonably likely to occur when the system is properly designed and operated. As discussed elsewhere, the final standard reflects the degree of emission limitation achievable through the application of the BSER which we have determined to be a highly efficient SCPC implementing partial CCS at a level sufficient to achieve the final standard—for such a unit utilizing bituminous coal that would be approximately 16 percent. In determining the predicted cost and performance of such a system, the EPA utilized information contained in updated DOE/NETL studies that assumed use of bituminous coal and an 85 percent capacity factor. Here we examine the effects of deviating from those assumed operational parameters on the achievability of the final standard of performance.[356] This is in keeping with the requirement that a standard of performance must be achievable accounting for all normal operating variability when a control system is properly designed, maintained, and operated. See Section III.H.1.c above.

1. Operational Fluctuations, Start-Ups, Shutdowns, and Malfunctions

Importantly, compliance with the standard must be demonstrated over a 12-operating-month average. The total CO_2 emissions (pounds of CO_2) over 12 operational months are summed and divided by the total gross output (in megawatt-hours) over the same 12 operational months. Such a compliance averaging period is very forgiving of short-term excursions that can be associated with non-routine events such as start-ups, shutdowns, and malfunctions. A new fossil fuel-fired steam generating EGU—if constructed—would, most likely, be built to serve base load power demand and would not be expected to routinely start-up or shutdown or ramp its capacity factor in order to follow load demand. Thus, planned start-up and shutdown events would only be expected to occur a few times during the course of a 12-operating-month compliance period. Malfunctions are unplanned and unpredictable events and emission excursions can happen at or around the time of the equipment malfunction. But a malfunctioning EGU that cannot be operated properly should be shut down until the malfunctioning equipment can be addressed and the EGU can be restarted to operate properly.

The post-combustion capture systems that have been utilized have proven to be reliable. The Boundary Dam facility has been operating full CCS successfully at commercial scale since October 2014. As described earlier, in evaluating results from the Mountaineer slip-

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[348] AEP Comments at pp. 93, 96 (Docket entry: EPA–HQ–OAR–2013–0495–10618).

[349] ''Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture.'' DOE/NETL–2011/1498 (September 2013) p. 49. Specifically, the report estimates the costs associated with acquiring rights to use the pore space in the geologic formation. Costs are estimated based on studies of subsurface rights acquisition for natural gas storage. The report also estimates costs for land acquisition for surface property rights. Id. p. 48.

[350] Bock, B., R. Rhudy, H. Herzog, M. Klett, J. Davidson, D.G. De La Torre Ugarte, and D. Simbeck. (2003). Economic Evaluation of CO_2 Storage and Sink Enhancement Options, Final Technical Report Prepared by Tennessee Valley Authority for DOE.

[351] As noted above, other sequestration-related costs are also estimated, including injection wells and equipment, pore volume acquisition, and long-term-liability. ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity Revision 2a, September 2013 DOE/NETL–2010/1397, p. 55.

[352] ''Overview of Monitoring Requirements for Geologic Storage Projects'', IEA Greenhouse Gas R&D Programme, Report Number PH4/29, November 2004.

[353] Cost Analysis for the Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells, U.S. Environmental Protection Agency Office of Water, EPA 816–R10–013, November 2010, pages 3–1, 5–42.

[354] Economic Evaluation of CO_2 Storage and Sink Enhancement Options, Tennessee Valley Authority, NETL and EPRI, December 2002.

[355] See ''CCS front end engineering & design report: American Electric Power Mountaineer CCS II Project. Phase 1'' at pp. 36–43. The company likewise explained the monitoring regime it would utilize to verify containment, and the well construction it would utilize to guarantee secure sequestration. Id. at pp. 44–54. Available at: *http://www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report.*

[356] Additional information can be found in a Technical Support Document (TSD)—''Achievability of the Standard for Newly Constructed Steam Generating EGUs'' available in the rulemaking docket.

stream demonstration, AEP and Alstom reported robust steady-state operation during all modes of power plant operation including load changes, and saw an availability of the CCS system of greater than 90 percent.[357]

2. Variations in Coal Type

The use of specific coal types can affect the amount of CO_2 that is emitted from a new coal-fired power plant. As previously discussed, the EPA utilized studies by the DOE/NETL to predict the cost and performance of new steam generating units. Based on those reports, the EPA predicts that a new SCPC burning low rank coal (subbituminous coal or dried lignite) would have an uncontrolled emission rate about 7 percent higher than a similar unit firing typical bituminous coal.[358] The EPA predicts that such a highly efficient new SCPC utilizing subbituminous coal or dried lignite would need to capture approximately 23 percent of the CO_2. The EPA also believes that it is technically feasible to do so, although additional cost would be entailed. The EPA has evaluated those costs and finds them to remain reasonable.[359] As shown in Table 8 above, the predicted cost remains within the estimated range for the other principal base load, dispatchable non-NGCC alternative technologies. Estimated capital cost using these coal types would also be somewhat higher, an estimated 23 percent increase.[360] The EPA finds these increases to be reasonable because, as discussed earlier, the costs are reasonably consistent with capital cost increases in previous NSPS. See Section V.H.4 above.

K. Emission Reductions Utilizing Partial CCS

Although the definition of ''standard of performance'' does not by its terms identify the amount of emissions from the category of sources and the amount of emission reductions achieved as factors the EPA must consider in determining the ''best system of emission reduction,'' the D.C. Circuit has stated that the EPA must do so. See *Sierra Club* v. *Costle,* 657 F.2d at 326 (''we can think of no sensible interpretation of the statutory words ''best . . . system'' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions'').[361] This is consistent with the Court's statements in *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d at 437 that it is necessary to ''[k]eep[] in mind Congress' intent that new plants be controlled to the 'maximum practicable degree' ''.

The final standard of performance will result in meaningful and significant emission reductions of GHG emissions from a new coal-fired steam generating unit. The EPA estimates that a new highly efficient 500 MW coal-fired SCPC meeting the final standard of 1,400 lb CO_2/MWh-g will emit about 354,000 fewer metric tons of CO_2 each year than that new highly efficient unit would have emitted otherwise. That is equivalent to taking about 75,000 vehicles off the road each year[362] and will result in over 14,000,000 fewer metric tons of CO_2 in a 40-year operating life. To emphasize the importance of constructing a highly efficient SCPC unit that includes partial CCS—the highly efficient 500 MW coal-fired SCPC with partial CCS would emit about 675,000 fewer metric tons of CO_2 each year than that from a new, less efficient coal-fired utility boiler with an assumed emission of 1,800 lb CO_2/MWh-g.

For comparison, see Table 12 below which provides the amount of CO_2 emissions captured each year by other CCS projects. These result show that, even though the emission reductions are significant, they are reasonably within the range of emission reductions that are currently being achieved now in existing facilities. For comparison, approximately 60,000,000 metric tons of CO_2 were supplied to U.S. EOR operations in 2013.[363]

TABLE 12—ANNUAL METRIC TONS OF CO_2 CAPTURED (OR PREDICTED TO CAPTURE) FROM CCS PROJECTS AND FROM A MODEL 500 MW PLANT MEETING THE FINAL STANDARD.

Project	CO_2 captured tonnes/year
AES Shady Point	66,000
AES Warrior Run	110,000
Southern Company Plant Barry	165,000
Searles Valley Minerals	270,000
New 500 MW SCPC EGU (1,400 lb CO_2/MWh-g)	354,000
Coffeyville Fertilizer	700,000
Boundary Dam #3	1,000,000
Petra Nova/NRG WA Parish	1,400,000
Dakota Gasification	3,000,000

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[357] *http://www.alstom.com/press-centre/2011/5/alstom-announces-sucessful-results-of-mountaineer-carbon-capture-and-sequestration-ccs-project/*. The Boundary Dam facility likewise is operating reliably (see Section V.D.3.a above). See also ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3'', DOE/NETL–2015/1723 (July 2015) at p. 36 (''[t]he capture and CO_2 compression technologies have commercial operating experience with demonstrated ability for high reliability'').

[358] For additional detail, see the Technical Support Document (TSD)—''Achievability of the Standard for Newly Constructed Steam Generating EGUs''—available in the rulemaking docket.

[359] The cost of the lignite drying equipment is assumed to be low compared to the cost of the carbon capture equipment. Further, pre-drying of the lignite reduces fuel, auxiliary power consumption and other O&M costs. *www.iea-coal.org.uk/documents/83436/9095/Techno-economics-of-modern-pre-drying-technologies-for-lignite-fired-power-plants,-CCC/241*.

[360] Note that the 23 percent increase in expected capital costs and the 23 percent CO_2 capture needed to meet the final standard are coincidental and are not correlated.

[361] *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of ''standard of performance,'' which revised the phrase ''best system'' to read, ''best technological system.'' The 1990 CAAA deleted ''technological,'' and thereby returned the phrase to how it read under the 1970 CAAA. The *Sierra Club* v. *Costle's* interpretation of this phrase to require consideration of the amount of air emissions remains valid for the phrase ''best system.''

[362] Using U.S. EPA Office of Transportation and Air Quality (OTAQ) estimate of average vehicle emissions of 4.7 tonnes/year.

[363] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

L. Further Development and Deployment of CCS Technology

Researchers at Carnegie Mellon University (CMU) have studied the history and the technological response to environmental regulations.[364] By examining U.S. research funding and patenting activity over the past century, the CMU researchers found that promulgation of national policy requiring large reductions in power-plant emissions resulted in a significant upswing in inventive activity to develop technologies to reduce those emissions. The researchers found that, following the 1970 Clean Air Act, there was a 10-fold increase in patenting activity directed at improving the SO_2 scrubbers that were needed to comply with stringent federal and state-level standards.

Much like carbon capture scrubbers today, the technology to capture and remove SO_2 from power plant flue gases was new to the industry and was not yet widely deployed at large coal-burning plants when the EPA first promulgated the 1971 standards.

Many of the early Flue Gas Desulfurization (FGD) units did not perform well, as the technology at that time was poorly understood and there was little or no prior experience on coal-fired power plants. In contrast, amine-based capture systems have a much longer history of reliable use at coal-fired plants and other industrial sources. There is also a better understanding of the amine process chemistry and overall process design—and project developers have much sophisticated analytical tools available today than in the 1970s during the development of FGD scrubber technologies.

While R&D efforts were essential to achieving improvements in FGD scrubber technology—and are also very important to improving carbon capture technologies, the influence of regulatory actions that establish commercial markets for advanced technologies cannot be minimized. The existence of national government regulation for SO_2 emissions control stimulated innovation, as shown by the patent analysis following initial SO_2 regulatory requirements for EGU emissions. The study author further found that regulatory stringency appears to be particularly important as a driver of innovation, both in terms of inventive activity and in terms of the communication processes involved in knowledge transfer and diffusion. Further, as electric power generation doubled, the operating and maintenance costs of FGD systems decline to 83 percent of their original level. This finding, which is very much in line with progress ratios determined in other industries, shows that quantifiable technological improvements can be shown to occur solely on the basis of the experience of operating an environmental control technology forced into being by government actions.

M. Technical and Geographic Aspects of Disposition of Captured CO_2

In the following sections of the preamble, we discuss issues associated with the disposition of captured CO_2: the ''S''—sequestration—in CCS. In this section, we review the existing processes, technologies, and geologic conditions that enable successful geologic sequestration (GS). In Section V.N., we discuss in detail the comprehensive, in-place regulatory structure that is currently available to oversee GS projects and assure their safety and effectiveness. Together, these discussions demonstrate that the technical feasibility of GS, another key component of a partial CCS unit, is adequately demonstrated. Sequestration is already well proven. CO_2 has been retained underground for eons in geologic (natural) repositories and the mechanisms by which CO_2 is trapped underground are well understood. The physical and chemical trapping mechanisms, along with the regulatory requirements and safeguards of the Underground Injection Control Program and complementary monitoring and reporting requirements of the GHGRP, together ensure that sequestered CO_2 will remain secure and provide the monitoring to identify and address potential leakage using Safe Drinking Water Act (SDWA) and CAA authorities (see Section V.N of this preamble).[365]

1. Geologic and Geographic Considerations for GS

Geologic sequestration (*i.e.,* long-term containment of a CO_2 stream in subsurface geologic formations) is technically feasible and available throughout most of the United States. GS is based on a demonstrated understanding of the processes that affect CO_2 fate in the subsurface; these processes can vary regionally as the subsurface geology changes. GS occurs through a combination of mechanisms including: (1) Structural and stratigraphic trapping (generally trapping below a low permeability confining layer); (2) residual CO_2 trapping (retention as an immobile phase trapped in the pore spaces of the geologic formation); (3) solubility trapping (dissolution in the in situ formation fluids); (4) mineral trapping (reaction with the minerals in the geologic formation and confining layer to produce carbonate minerals); and (5) preferential adsorption trapping (adsorption onto organic matter in coal and shale).[366] These mechanisms are functions of the physical and chemical properties of CO_2 and the geologic formations into which the CO_2 stream is injected. Subsurface formations suitable for GS of CO_2 captured from affected EGUs are geographically widespread throughout most parts of the United States.

Storage security is expected to increase over time through post-closure, resulting in a decrease in potential risks.[367] This expectation is based in part on a technical understanding of the variety of trapping mechanisms that work to reduce CO_2 mobility over time.[368] In addition, site characterization, site operations, and monitoring strategies can work in combination to promote storage security.

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[364] See Technical Support Document/Memorandum ''History Of Flue Gas Desulfurization in the United States'' (July 11, 2015) summarizing the doctoral dissertation of Margaret R. Taylor, ''The Influence of Government Actions on Innovative Activities in the Development of Environmental Technologies to Control Sulfur Dioxide Emissions from Stationary Sources,'' MA dissertation submitted to the Carnegie Institute of Technology, Carnegie Mellon University in partial fulfillment of the requirements for the degree of Doctor of Philosophy in Engineering and Public Policy, Pittsburgh, PA, January 2001.

[365] See also *Carbon Sequestration Council and Southern Company Services* v. *EPA,* No. 14–1406 (D.C. Cir. June 2, 2015) at *10 (''[c]arbon capture and storage is an emerging climate change mitigation program that involves capturing carbon dioxide from industrial sources, compressing it into a 'supercritical fluid,' and injecting that fluid underground for the purposes of geologic sequestration, with the goal of preventing the carbon from reentering the atmosphere. Because the last of these steps—geologic sequestration of the supercritical carbon dioxide—involves that injection of fluid into underground wells, it is subject to regulation under the Safe Drinking Water Act'').

[366] See, *e.g.,* USEPA. 2008. Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide.

[367] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 47.

[368] See, *e.g.,* Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

The effectiveness of long-term trapping of CO_2 has been demonstrated by natural analogs in a range of geologic settings where CO_2 has remained trapped for millions of years.[369] For example, CO_2 has been trapped for more than 65 million years in the Jackson Dome, located near Jackson, Mississippi.[370] Other examples of natural CO_2 sources include Bravo Dome and McElmo Dome in Colorado and New Mexico, respectively. These natural storage sites are themselves capable of holding volumes of CO_2 that are larger than the volume of CO_2 expected to be captured from a fossil fuel-fired EGU. In 2010, the Department of Energy (DOE) estimated current CO_2 reserves of 594 million metric tons at Jackson Dome, 424 million metric tons at Bravo Dome, and 530 million metric tons at McElmo Dome.[371]

GS is feasible in different types of geologic formations including deep saline formations (formations with high salinity formation fluids) or in oil and gas formations, such as where injected CO_2 increases oil production efficiency through a process referred to as enhanced oil recovery (EOR). Both deep saline and oil and gas formation types are widely available in the United States. The geographic availability of deep saline formations and EOR is shown in Figure 1 below.[372] As shown in the figure, there are 39 states for which onshore and offshore deep saline formation storage capacity has been identified.[373] EOR operations are currently being conducted in 12 states. An additional 17 states have geology that is amenable to EOR operations. Figure 1 also shows areas that are within 100 kilometers (62 miles) of where storage capacity has been identified.[374] There are 10 states with operating CO_2 pipelines and 18 states that are within 100 kilometers (62 miles) of an active EOR location.

CO_2 may also be used for other types of enhanced recovery, such as for natural gas production. Reservoirs such as unmineable coal seams also offer the potential for geologic storage.[375] Enhanced coalbed methane recovery is the process of injecting and storing CO_2 in unmineable coal seams to enhance methane recovery. These operations take advantage of the preferential chemical affinity of coal for CO_2 relative to the methane that is naturally found on the surfaces of coal. When CO_2 is injected, it is adsorbed to the coal surface and releases methane that can then be captured and produced. This process effectively ''locks'' the CO_2 to the coal, where it remains stored. DOE has identified over 54 billion metric tons of potential CO_2 storage capacity in unmineable coal across 21 states.[376] The availability of unmineable coal seams is shown in Figure 1 below.

As discussed below in Section M.7, a few states do not have geologic conditions suitable for GS, or may not be located in proximity to these areas. However, in some cases, demand in those states can be served by coal-fired power plants located in areas suitable for GS, and in other cases, coal-fired power plants are unlikely to be built in those areas for other reasons, such as the lack of available coal or state law prohibitions and restrictions against coal-fired power plants.[377]

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[369] Holloway, S., J. Pearce, V. Hards, T. Ohsumi, and J. Gale. 2007. Natural Emissions of CO_2 from the Geosphere and their Bearing on the Geological Storage of Carbon Dioxide. Energy 32: 1194–1201.

[370] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[371] DiPietro, P., Balash, P. & M. Wallace. A Note on Sources of CO_2 Supply for Enhanced-Oil Recovery Operations. SPE Economics & Management. April 2012.

[372] A color version of the figure, which readers may find easier to view, can be found in the technical support document on geographic availability in the rulemaking docket.

[373] Alaska is not shown in Figure 1; it has deep saline formation storage capacity, geology amenable to EOR operations, and potential GS capacity in unmineable coal seams.

[374] The distance of 100 kilometers reflects assumptions in DOE–NETL cost estimates which the EPA used for cost estimation purposes. See ''Carbon Dioxide and Transport and Storage Costs in NETL Studies'', DOE/NETL–2014/1653 (May 2014).

[375] Other types of opportunities include organic shales and basalt.

[376] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL).

[377] Similarly, as discussed below, the U.S. territories lack available coal, do not currently have coal-fired power plants, and, as a result, are not expected to see new coal-fired power plants. Hawaii is not expected to constructed new coal plants as it intends to utilize 100 percent renewable energy sources by 2050.

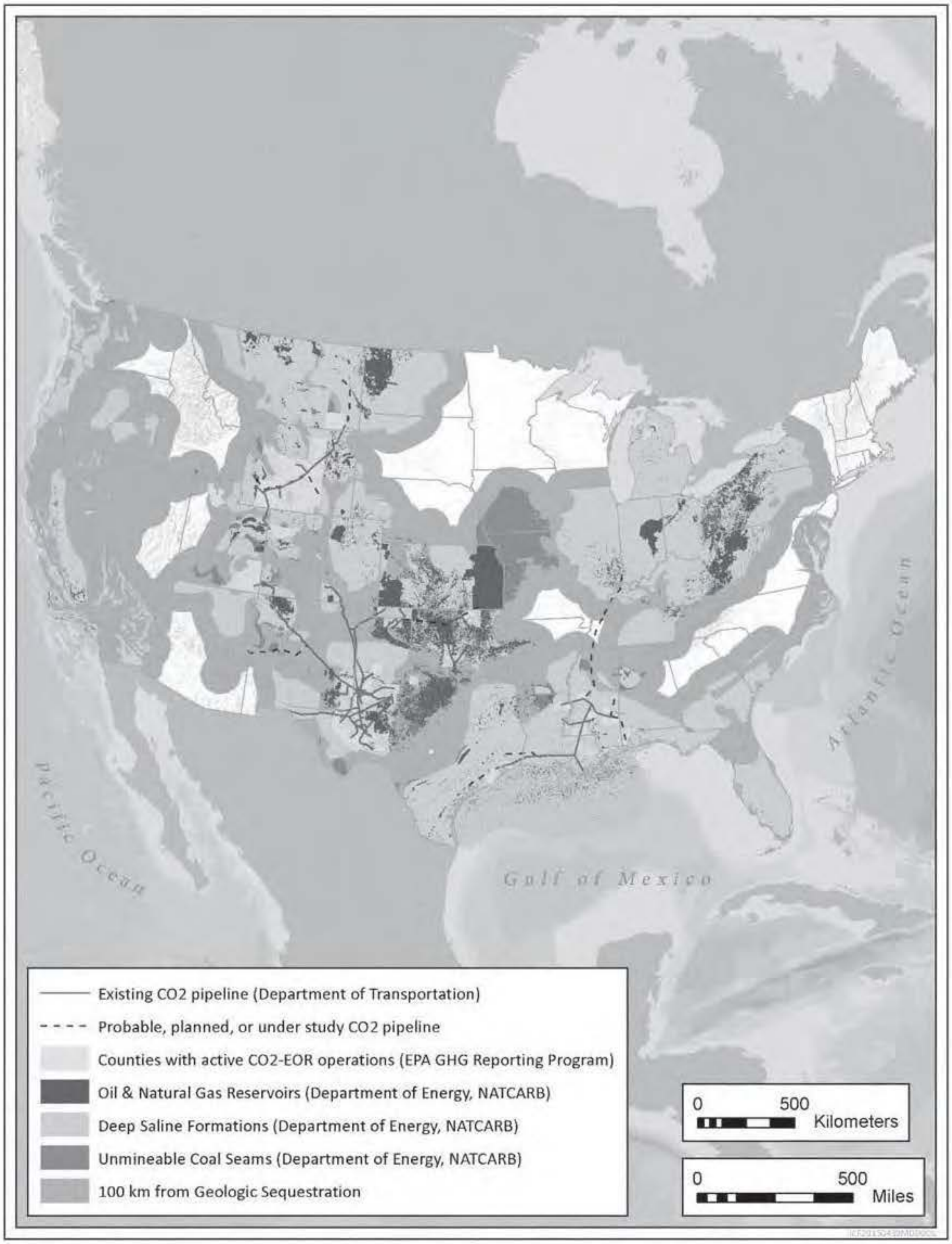

Figure 1: Geologic Sequestration in the Continental United States

Figure 2 - Electrical Transmission Lines across the Continental United States[378]

2. Availability of Geologic Sequestration in Deep Saline Formations

The DOE and the United States Geological Survey (USGS) have independently conducted preliminary analyses of the availability and potential CO_2 sequestration capacity of deep saline formations in the United States. DOE estimates are compiled by the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB) using volumetric models and published in a Carbon Utilization and Storage Atlas.[379] DOE estimates that areas of the United States

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[378] Ventyx Velocity Suite Online. April 2015.

[379] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL).

with appropriate geology have a sequestration potential of at least 2,035 billion metric tons of CO_2 in deep saline formations. According to DOE and as noted above, at least 39 states have geologic characteristics that are amenable to deep saline GS in either onshore or offshore locations. In 2013, the USGS completed its evaluation of the technically accessible GS resources for CO_2 in U.S. onshore areas and state waters using probabilistic assessment.[380] The USGS estimates a mean of 3,000 billion metric tons of subsurface CO_2 sequestration potential, including saline and oil and gas reservoirs, across the basins studied in the United States.

The DOE has created a network of seven Regional Carbon Sequestration Partnerships (RCSPs) to deploy large-scale field projects in different geologic settings across the country to demonstrate that GS can be achieved safely, permanently, and economically at large scales. Collectively, the seven RCSPs represent regions encompassing 97 percent of coal-fired CO_2 emissions, 97 percent of industrial CO_2 emissions, 96 percent of the total land mass, and essentially all the geologic sequestration sites in the United States potentially available for GS.[381] The seven partnerships include more than 400 organizations spanning 43 states (and four Canadian provinces).[382] RCSP project objectives are to inject at least one million metric tons of CO_2. In April 2015, DOE announced that CCS projects supported by the department have safely and permanently stored 10 million metric tons of CO_2.[383]

Eight RCSP ''Development Phase'' projects have been initiated and five of the eight projects are injecting or have completed CO_2 injection into deep saline formations. Three of these projects have already injected more than one million metric tons each, and one, the Cranfield Site, injected over eight million metric tons of CO_2 between 2009 and 2013.[384] Various types of technologies for monitoring CO_2 in the subsurface and air have been employed at these projects, such as seismic methods (crosswell seismic, 3–D and 4–D seismic, and vertical seismic profiling), atmospheric CO_2 monitoring, soil gas sampling, well and formation pressure monitoring, and surface and ground water monitoring.[385] No CO_2 leakage has been reported from these sites, which further supports the availability of effective GS.

3. Availability of CO_2 Storage via EOR

Although the determination that the BSER is adequately demonstrated and the regulatory impact analysis for this rule relies on GS in deep saline formations, the EPA also recognizes the potential for securely sequestering CO_2 via EOR.

EOR is a technique that is used to increase the production of oil. Approaches used for EOR include steam injection, injection of specific fluids such as surfactants and polymers, and gas injection including nitrogen and CO_2. EOR using CO_2, sometimes referred to as ''CO_2 flooding'' or CO_2-EOR, involves injecting CO_2 into an oil reservoir to help mobilize the remaining oil to make it more amenable for recovery. The crude oil and CO_2 mixture is then recovered and sent to a separator where the crude oil is separated from the gaseous hydrocarbons, native formation fluids, and CO_2. The gaseous CO_2-rich stream then is typically dehydrated, purified to remove hydrocarbons, re-compressed, and re-injected into the reservoir to further enhance oil recovery. Not all of the CO_2 injected into the oil reservoir is recovered and re-injected. As the CO_2 moves from the injection point to the production well, some of the CO_2 becomes trapped in the small pores of the rock, or is dissolved in the oil and water that is not recovered. The CO_2 that remains in the reservoir is not mobile and becomes sequestered.

The amount of CO_2 used in an EOR project depends on the volume and injectivity of the reservoir that is being flooded and the length of time the EOR project has been in operation. Initially, all of the injected CO_2 is newly received. As discussed above, as the project matures, some CO_2 is recovered with the oil and the recovered CO_2 is separated from the oil and recycled so that it can be re-injected into the reservoir in addition to new CO_2 that is received. If an EOR operator will not require the full volume of CO_2 available from an EGU, the EGU has other options such as sending the CO_2 to other EOR operators, or sending it to deep saline formation GS facilities.

CO_2 used for EOR may come from anthropogenic or natural sources. The source of the CO_2 does not impact the effectiveness of the EOR operation. CO_2 capture, treatment and processing steps provide a concentrated stream of CO_2 in order to meet the needs of the intended end use. CO_2 pipeline specifications of the U.S. Department of Transportation Pipeline Hazardous Materials Safety Administration found at 49 CFR part 195 (Transportation of Hazardous Liquids by Pipeline) apply regardless of the source of the CO_2 and take into account CO_2 composition, impurities, and phase behavior. Additionally, EOR operators and transport companies have specifications related to the composition of the CO_2 stream. The regulatory requirements and company specifications ensure EOR operators receive a known and consistent CO_2 stream.

EOR has been successfully used at numerous production fields throughout the United States to increase oil recovery. The oil industry in the United States has over 40 years of experience with EOR. An oil industry study in 2014 identified more than 125 EOR projects in 98 fields in the United States.[386] More than half of the projects evaluated in the study have been in operation for more than 10 years, and many have been in operation for more than 30 years. This experience provides a strong foundation for demonstrating successful CO_2 injection and monitoring technologies, which are needed for safe and secure GS (see Section N below) that can be used for deployment of CCS across geographically diverse areas.

Currently, 12 states have active EOR operations and most have developed an extensive CO_2 infrastructure, including pipelines, to support the continued operation and growth of EOR. An additional 18 states are within 100 kilometers (62 miles) of current EOR operations. See Figure 1 above. The vast majority of EOR is conducted in oil reservoirs in the Permian Basin, which extends through southwest Texas and southeast New Mexico. States where EOR is utilized include Alabama, Colorado, Louisiana, Michigan,

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[380] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources—Results: U.S. Geological Survey Circular 1386, p. 41, *http://pubs.usgs.gov/circ/1386/*.

[381] *http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research/regional-partnerships*.

[382] *http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research/regional-partnerships*.

[383] *http://energy.gov/articles/milestone-energy-department-projects-safely-and-permanently-store-10-million-metric-tons*.

[384] U.S. Department of Energy, National Energy Technology Laboratory, Project Facts, Southeast Regional Carbon Sequestration Partnership—Development Phase, Cranfield Site and Citronelle Site Projects, NT42590, October 2013. Available at: *http://www.netl.doe.gov/publications/factsheets/project/NT42590.pdf*.

[385] A description of the types of monitoring technologies employed at RCSP projects can be found here: *http://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-infrastructure/regional-partnership-development-phase-iii*.

[386] Koottungal, Leena, 2014, 2014 Worldwide EOR Survey, Oil & Gas Journal, Volume 112, Issue 4, April 7, 2014 (corrected tables appear in Volume 112, Issue 5, May 5, 2014).

Mississippi, New Mexico, Oklahoma, Texas, Utah, and Wyoming. Several commenters raised concerns about the volume of CO_2 used in EOR projects relative to the scale of EGU emissions and the demand for CO_2 for EOR projects. At the project level, the volume of CO_2 already injected for EOR and the duration of operations are of similar magnitude to the duration and volume of CO_2 expected to be captured from fossil fuel-fired EGUs. The volume of CO_2 used in EOR operations can be large (*e.g.,* 55 million tons of CO_2 were stored in the SACROC unit in the Permian Basin over 35 years), and operations at a single oil field may last for decades, injecting into multiple parts of the field.[387] According to data reported to the EPA's GHGRP, approximately 60 million metric tons of CO_2 were supplied to EOR in the United States in 2013.[388] Approximately 70 percent of this total CO_2 supplied was produced from natural (geologic) CO_2 sources and approximately 30 percent was captured from anthropogenic sources.[389]

A DOE-sponsored study has analyzed the geographic availability of applying EOR in 11 major oil producing regions of the United States and found that there is an opportunity to significantly increase the application of EOR to areas outside of current operations.[390] DOE-sponsored geologic and engineering analyses show that expanding EOR operations into areas additional to the capacity already identified and applying new methods and techniques over the next 20 years could utilize 18 billion metric tons of anthropogenic CO_2 and increase total oil production by 67 billion barrels. The study found that one of the limitations to expanding CO_2 use in EOR is the lack of availability of CO_2 in areas where reservoirs are most amenable to CO_2 flooding.[391] DOE's Carbon Utilization and Storage Atlas identifies 29 states with oil reservoirs amenable to EOR, 12 of which currently have active EOR operations. A comparison of the current states with EOR operations and the states with potential for EOR shows that an opportunity exists to expand the use of EOR to regions outside of current areas. The availability of anthropogenic CO_2 in areas outside of current sources could drive new EOR projects by making more CO_2 locally available.

Some commenters raised concerns that data are extremely limited on the extent to which EOR operations permanently sequester CO_2, and the efficacy of long term storage, or that the EOR industry does not have the requisite experience with and technical knowledge of long-term CO_2 sequestration. The EPA disagrees with these commenters. Several EOR sites, which have been operated for years to decades, have been studied to evaluate the viability of safe and secure long-term sequestration of injected CO_2. Examples are identified below.

CO_2 has been injected in the SACROC Unit in the Permian basin since 1972 for EOR purposes. One study evaluated a portion of this project, and estimated that the injection operations resulted in final sequestration of about 55 million tons of CO_2.[392] This study used modeling and simulations, along with collection and analysis of seismic surveys, and well logging data, to evaluate the ongoing and potential CO_2 trapping occurring through various mechanisms. The monitoring at this site demonstrated that CO_2 can become trapped in geologic formations. In a separate study in the SACROC Unit, the Texas Bureau of Economic Geology conducted an extensive groundwater sampling program to look for evidence of CO_2 leakage in the shallow freshwater aquifers. No evidence of leakage was detected.[393]

The International Energy Agency Greenhouse Gas Programme conducted an extensive monitoring program at the Weyburn oil field in Saskatchewan between 2000 and 2010 (the site receiving CO_2 captured by the Dakota Gasification synfuel plant discussed in Section V.E.2.a above). During that time over 16 million metric tons of CO_2 were safely sequestered as evidenced by soil gas surveys, shallow groundwater monitoring, seismic surveys and wellbore integrity testing. An extensive shallow groundwater monitoring program revealed no significant changes in water chemistry that could be attributed to CO_2 storage operations.[394] The International Energy Agency Greenhouse Gas Programme developed a best practices manual for CO_2 monitoring at EOR sites based on the comprehensive analysis of surface and subsurface monitoring methods applied over the 10 years.[395]

The Texas Bureau of Economic Geology also has been testing a wide range of surface and subsurface monitoring tools and approaches to document sequestration efficiency and sequestration permanence at the Cranfield oilfield in Mississippi (see Section L.1 above).[396] As part of a DOE Southeast Regional Carbon Sequestration Partnership study, Denbury Resources injected CO_2 into a depleted oil and gas reservoir at a rate greater than 1.2 million tons/year. Texas Bureau of Economic Geology is currently evaluating the results of several monitoring techniques employed at the Cranfield project and preliminary findings indicate no impact to groundwater.[397] The project also demonstrates the availability and effectiveness of many different monitoring techniques for tracking CO_2 underground and detecting CO_2 leakage to ensure CO_2 remains safely sequestered.

As discussed in Section M.1 above and as shown in Figure 1, the United States has widespread potential for storage, including in deep saline formations and oil and gas formations. However, some commenters maintained that the EPA's information regarding availability of GS sites is overly general and ignores important individual considerations. A number of commenters, for example, maintained that site conditions often make monitoring difficult or impossible, so

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[387] Han, Weon S., McPherson, B J., Lichtner, P C., and Wang, F P. ''Evaluation of CO_2 trapping mechanisms at the SACROC northern platform, Permian basin, Texas, site of 35 years of CO_2 injection.'' American Journal of Science 310. (2010): 282–324.

[388] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

[389] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

[390] ''Improving Domestic Energy Security and Lowering CO_2 Emissions with ''Next Generation'' CO_2-Enhanced Oil Recovery'', Advanced Resources International, Inc. (ARI), 2011. Available at: *http://www.netl.doe.gov/research/energy-analysis/publications/details?pub=df02ffba-6b4b-4721-a7b4-04a505a19185.*

[391] ''Improving Domestic Energy Security and Lowering CO_2 Emissions with ''Next Generation'' CO_2-Enhanced Oil Recovery'', Advanced Resources International, Inc. (ARI), 2011. Available at: *http://www.netl.doe.gov/research/energy-analysis/publications/details?pub=df02ffba-6b4b-4721-a7b4-04a505a19185.*

[392] Han, Weon S., McPherson, B J., Lichtner, P C., and Wang, F P. ''Evaluation of CO_2 trapping mechanisms at the SACROC northern platform, Permian basin, Texas, site of 35 years of CO_2 injection.'' American Journal of Science 310. (2010): 282–324.

[393] Romanak, K.D., Smyth, R.C., Yang, C., and Hovorka, S., Detection of anthropogenic CO_2 in dilute groundwater: field observations and geochemical modeling of the Dockum aquifer at the SACROC oilfield, West Texas, USA: presented at the 9th Annual Conference on Carbon Capture & Sequestration, Pittsburgh, PA, May 10–13, 2010. GCCC Digital Publication Series #10–06.

[394] Roston, B., and S. Whittaker (2010), 10+ years of the IEA–GHG Weyburn-Midale CO_2 monitoring and storage project; success and lessons learned from multiple hydrogeological investigations, to be published in Energy Procedia, Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

[395] Hitchon, B. (Editor), 2012, Best Practices for Validating CO_2 Geological Storage: Geoscience Publishing, p. 353.

[396] *http://www.beg.utexas.edu/gccc/cranfield.php.*

[397] *http://www.beg.utexas.edu/gccc/cranfield.php.*

that sites are not available as a practical matter.[398] Commenter American Electric Power pointed to its own experience in siting monitoring wells for its pilot plant Mountaineer CCS project, which involved protracted time and expense to eventually site monitoring wells.[399] Other commenters noted significant geographic disparity in GS site availability, claiming absence of sites in southeastern areas of the country.[400]

Project- and site-specific factors do influence where CO_2 can be safely sequestered. However, as outlined above, there is widespread potential for GS in the United States. If an area does not have a suitable GS site, EGUs can either transport CO_2 to GS sites via CO_2 pipelines (see Section M.5 below), or they may choose to locate their units closer to GS sites and provide electric power to customers through transmission lines (see Figure 2 and Section M.7). In addition, there are alternative means of complying with the final standards of performance that do not necessitate use of partial CCS, so any siting difficulties based on lack of a CO_2 repository would be obviated. See *Portland Cement Ass'n* v. *EPA,* 665 F. 3d 177, 191 (D.C. Cir. 2011), holding that the EPA could adopt section 111 standards of performance based on the performance of a kiln type that kilns of older design would have great difficulty satisfying, since, among other things, there were alternative methods of compliance available should a new kiln of this older design be built.

4. Alternatives to Geologic Sequestration

Potential alternatives to sequestering CO_2 in geologic formations are emerging. These relatively new potential alternatives may offer the opportunity to offset the cost of CO_2 capture. For example, captured anthropogenic CO_2 may be stored in solid carbonate materials such as precipitated calcium carbonate (PCC) or magnesium or calcium carbonate, bauxite residue carbonation, and certain types of cement through mineralization. PCC is produced through a chemical reaction process that utilizes calcium oxide (quicklime), water, and CO_2. Likewise, the combination of magnesium oxide and CO_2 results in a precipitation reaction where the CO_2 becomes mineralized. The carbonate materials produced can be tailored to optimize performance in specific industrial and commercial applications. These carbonate materials have been used in the construction industry and, more recently and innovatively, in cement production processes to replace Portland cement.

The Skyonics Skymine project, which opened its demonstration project in October 2014, is an example of captured CO_2 being used in the production of carbonate products. This plant converts CO_2 into commercial products. It captures over 75,000 tons of CO_2 annually from a San Antonio, Texas, cement plant and converts the CO_2 into other products, including sodium carbonate, sodium bicarbonate, hydrochloric acid and bleach.[401]

A few commenters suggested that CO_2 utilization technologies alternative to GS are being commercialized, and that these should be included as compliance options for this rule. The rule generally requires that captured CO_2 be either injected on-site for geologic sequestration or transferred offsite to a facility reporting under 40 CFR subpart RR. The EPA does not believe that the emerging technologies just discussed are sufficiently advanced to unqualifiedly structure this final rule to allow for their use. Nor are there plenary systems of regulatory control and GHG reporting for these approaches, as there are for geologic sequestration. Nonetheless, as stated above, these technologies not only show promise, but could potentially be demonstrated to show permanent storage of CO_2.

In the January 2014 proposal, the EPA noted that it would need to adopt a mechanism to evaluate these alternative technologies before any could be used in lieu of geologic sequestration. 79 FR at 1484. The EPA is establishing such a mechanism in this final rule. See § 60.5555(g). The rule provides for a case-by-case adjudication by the EPA of applications seeking to demonstrate to the EPA that a non-geologic sequestration technology would result in permanent confinement of captured CO_2 from an affected EGU. The criteria to be addressed in the application, and evaluated by the EPA, are drawn from CAA section 111(j), which provides an analogous mechanism for case-by-case approval of innovative technological systems of continuous emission reduction which have not been adequately demonstrated. Applicants would need to demonstrate that the proposed technology would operate effectively, and that captured CO_2 would be permanently stored. Applicants must also demonstrate that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare or safety. In evaluating applications, the EPA may conduct tests itself or require the applicant to conduct testing in support of its application. Any application would be publicly noticed, and the EPA would solicit comment on the application and on intended action the EPA might take. The EPA could also provide a conditional approval of an application on operating results from a proscribed period. The EPA could also terminate an approval, including a termination based on operating results calling into question a technology's effectiveness.

As noted at proposal, given the unlikelihood of new coal-fired EGUs being constructed, the EPA does not expect there to be many (if any) applications for use of non-geologic sequestration technology. 79 FR at 1484.

5. Availability of Existing or Planned CO_2 Pipelines

CO_2 pipelines are the most economical and efficient method of transporting large quantities of CO_2.[402] CO_2 has been transported via pipelines in the United States for nearly 40 years. Over this time, the design, construction, operation, and safety requirements for CO_2 pipelines have been proven, and the U.S. CO_2 pipeline network has been safely used and expanded. The Pipeline and Hazardous Materials Safety Administration (PHMSA) reported that in 2013 there were 5,195 miles of CO_2 pipelines operating in the United States. This represents a seven percent increase in CO_2 pipeline miles over the previous year and a 38 percent increase in CO_2 pipeline miles since 2004.[403]

Some commenters argued that the existing CO_2 pipeline capacity is not adequate and that CO_2 pipelines are not available in a majority of the United States.

The EPA does not agree. The CO_2 pipeline network in the United States has almost doubled in the past ten years in order to meet growing demands for CO_2 for EOR. CO_2 transport companies have recently proposed initiatives to expand the CO_2 pipeline network. Several hundred miles of dedicated CO_2 pipeline are under construction, planned, or proposed, including

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[398] Comments of Southern Co., p. 38 (Docket entry: EPA–HQ–OAR–2013–0495–10095).

[399] Comments of AEP pp. 93, 96 (Docket entry: EPA–HQ–OAR–2013–0495–10618).

[400] Comments of Duke Energy, pp. 24–5 Docket entry: EPA–HQ–OAR–2013–0495–9426); UARG, pp. 53, 57 (Docket entry: EPA–HQ–OAR–2013–0495–9666) citing Cichanowicz (2012).

[401] *http://skyonic.com/technologies/skymine.*

[402] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 36.

[403] ''Annual Report Mileage for Hazardous Liquid or Carbon Dioxide Systems'', U.S. Pipeline and Hazardous Materials Safety Administration, March 2, 2015. Available at: *http://www.phmsa.dot.gov/pipeline/library/data-stats.*

projects in Colorado, Louisiana, Montana, New Mexico, Texas, and Wyoming.

Examples are identified below.

Kinder Morgan has reported several proposed pipeline projects including the proposed expansion of the existing Cortez CO_2 pipeline, crossing Colorado, New Mexico, and Texas, to increase the CO_2 transport capacity from 1.35 billion cubic feet per day (Bcf/d) to 1.7 Bcf/d, to support the expansion of CO_2 production capacity at the McElmo Dome production facility in Colorado. The Cortez pipeline expansion is expected to be placed into service in 2015.[404]

Denbury reported that the company utilized approximately 70 million cubic feet per day of anthropogenic CO_2 in 2013 and that an additional approximately 115 million cubic feet per day of anthropogenic CO_2 may be utilized in the future from currently planned or future construction of facilities and associated pipelines in the Gulf Coast region.[405] Denbury also initiated transport of CO_2 from a Wyoming natural gas processing plant in 2013 and reported transporting approximately 22 million cubic feet per day of CO_2 in 2013 from that plant alone.[406]

Denbury completed the final section of the 325-mile Green Pipeline for transporting CO_2 from Donaldsonville, Louisiana, to EOR oil fields in Texas.[407] Denbury completed construction and commenced operation of the 232-mile Greencore Pipeline in 2013; the Greencore pipeline transports CO_2 to EOR fields in Wyoming and Montana.[408]

A project being constructed by NRG and JX Nippon Oil & Gas Exploration (Petra Nova) would capture CO_2 from a power plant in Fort Bend County, Texas for transport to EOR sites in Jackson County, Texas through an 82-mile CO_2 pipeline.[409] The project is anticipated to commence operation in 2016.[410]

Some commenters suggested that there may be challenges associated with the safety of transporting supercritical CO_2 over long distances, or that the EPA did not adequately consider the potential non-air environmental impacts of the construction of CO_2 pipelines.

The EPA has carefully evaluated the safety of pipelines used to transport captured CO_2 and determined that pipelines can indeed convey captured CO_2 to sequestration sites with certainty and provide full protection of human health and the environment. 76 FR at 48082–83 (Aug. 8, 2011); 79 FR 352, 354 (Jan. 3, 2014). Existing and new CO_2 pipelines are comprehensively regulated by the Department of Transportation's Pipeline Hazardous Material Safety Administration. The regulations govern pipeline design, construction, operation and maintenance, and emergency response planning. See generally 49 CFR 195.2. Additional regulations address pipeline integrity management by requiring heightened scrutiny to assure the quality of pipeline integrity in areas with a higher potential for adverse consequences. See 49 CFR 195.450 and 195.452. On-site pipelines are not subject to the Department of Transportation standards, but rather adhere to the Pressure Piping standards of the American Society of Mechanical Engineers (ASME B31), which the EPA has found would ensure that piping and associated equipment meet certain quality and safety criteria sufficient to prevent releases of CO_2, such that certain additional requirements were not necessary (See 79 FR 358–59 (Jan. 3, 2014)).[411] These existing controls over CO_2 pipelines assure protective management, guard against releases, and assure that captured CO_2 will be securely conveyed to a sequestration site.

6. States With Emission Standards That Would Require CCS

Several states have established emission performance standards or other measures to limit emissions of GHGs from new EGUs that are comparable to or more stringent than the final standard in this rulemaking. For example, in September 2006, California Governor Schwarzenegger signed into law Senate Bill 1368. The law limits long-term investments in base load generation by the state's utilities to power plants that meet an emissions performance standard jointly established by the California Energy Commission and the California Public Utilities Commission. The Energy Commission has designed regulations that establish a standard for new and existing base load generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lb CO_2/MWh.

In May 2007, Washington Governor Gregoire signed Substitute Senate Bill 6001, which established statewide GHG emissions reduction goals, and imposed an emission standard that applies to any base load electric generation that commenced operation after June 1, 2008 and is located in Washington, whether or not that generation serves load located within the state. Base load generation facilities must initially comply with an emission limit of 1,100 lb CO_2/MWh.

In July 2009, Oregon Governor Kulongoski signed Senate Bill 101, which mandated that facilities generating base load electricity, whether gas- or coal-fired, must have emissions equal to or less than 1,100 lb CO_2/MWh, and prohibited utilities from entering into long-term purchase agreements for base load electricity with out-of-state facilities that do not meet that standard.

In 2012 New York established emission standards of CO_2 at 925 lb CO_2/MWh for new and expanded base load fossil fuel-fired plants.

In May 2007, Montana Governor Schweitzer signed House Bill 25, adopting a CO_2 emissions performance standard for EGUs in the state. House Bill 25 prohibits the state Public Utility Commission from approving new EGUs primarily fueled by coal unless a minimum of 50 percent of the CO_2 produced by the facility is captured and sequestered.

On January 12, 2009, Illinois Governor Blagojevich signed Senate Bill 1987, the Clean Coal Portfolio Standard Law. The legislation establishes emission standards for new power plants that use coal as their primary feedstock. From 2009–2015, new coal-fueled power plants must capture and store 50 percent of the carbon emissions that the facility would otherwise emit; from 2016–2017, 70 percent must be captured and stored; and after 2017, 90 percent must be captured and stored.

7. Coal-by-Wire

In addition, as discussed in the proposal, electricity demand in states

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[404] "Form 10–K: Annual Report Pursuant to Section 13 or 15(d) of the Security and Exchange Act of 1934, For the Fiscal Year Ended December 31, 2014", Kinder Morgan, February 2015. Available at: *http://ir.kindermorgan.com/sites/kindermorgan.investorhq.businesswire.com/files/report/additional/KMI–2014–10K_Final.pdf.*

[405] "2013 Annual Report", Denbury, April 2014. Available at *http://www.denbury.com/files/doc_financials/2013/Denbury_Final_040814.pdf.*

[406] "CO_2 Sources", Denbury, 2015. Available at: *http://www.denbury.com/operations/rocky-mountain-region/co2-sources-and-pipelines/default.aspx.*

[407] *http://www.denbury.com/operations/gulf-coast-region/Pipelines/default.aspx.*

[408] "CO_2 Pipelines", Denbury, 2014. Available at: *http://www.denbury.com/operations/rocky-mountain-region/COsub2-sub-Pipelines/default.aspx.*

[409] "The West Ranch CO_2-EOR Project, NRG Fact Sheet", NRG, 2014. Available at: *www.nrg.com/documents/business/pla-2014-west-ranch-fact-sheet.pdf.*

[410] "WA Parish Carbon Capture Project", NRG, 2015. Available at: *www.nrg.com/sustainability/strategy/enhance-generation/carbon-capture/wa-parish-ccs-project/.*

[411] See the B31 Code for pressure piping, developed by the American Society of Mechanical Engineers, Pipeline Transportation Systems for liquid hydrocarbons and other liquids.

that may not have geologic sequestration sites may be served by coal-fired electricity generation built in nearby areas with geologic sequestration, and this electricity can be delivered through transmission lines. This method, known as ''coal-by-wire,'' has long been used in the electricity sector because siting a coal-fired power plant near the coal mine and transmitting the generation long distances to the load area is generally less expensive than siting the plant near the load area and shipping the coal long distances.

For example, we noted in the proposal that there are many examples where coal-fired power generated in one state is used to supply electricity in other states. In the proposal we specifically noted that historically nearly 40 percent of the power for the City of Los Angeles was provided from two coal-fired power plants located in Arizona and Utah and Idaho Power, which serves customers in Idaho and Eastern Oregon, meets its demand in part from coal-fired power plants located in Wyoming and Nevada. 79 FR at 1478.

In the Technical Support Document on Geographic Availability (Geographic Availability TSD), we explore in greater detail the issue of coal-by-wire and the ability of demand in areas without geologic sequestration to be served by coal generation located in areas that have access to geologic sequestration. Figure 1 of this preamble (a color version of which is provided as Figure 1 of the Geographic Availability TSD) depicts areas of the country with: (1) existing CO_2 pipeline; (2) probable, planned, or under study CO_2 pipeline; (3) counties with active CO_2-EOR operations; (4) oil and natural gas reservoirs; (5) deep saline formations; (6) unmineable coal seams; and (7) areas 100 kilometers from geologic sequestration. As demonstrated by Figure 1, the vast majority of the country has existing or planned CO_2 pipeline, active CO_2-EOR operations, the necessary geology for CO_2 storage, or is within 100 kilometers of areas with geologic sequestration.[412] A review of Figure 1 indicates limited areas that do not fall into these categories.

As an initial matter, we note that the data included in Figure 1 is a conservative outlook of potential areas available for the development of CO_2 storage in that we include only areas that have been assessed to date. Portions of the United States—such as the State of Minnesota—have not yet been assessed and thus are depicted as not having geological formations suitable for CO_2 storage, even though assessment could in fact reveal additional formations.[413]

As one considers the areas on the map depicted in Figure 1 that fall outside of the above enumerated categories, in many instances, we find areas with low population density, areas that are already served by transmission lines that could deliver coal-by-wire, and/or areas that have made policy or other decisions not to pursue a resource mix that includes coal. In many of these areas, utilities, electric cooperatives, and municipalities have a history of joint ownership of coal-fired generation outside the region or contracting with coal and other generation in outside areas to meet their demand. Some of the relevant areas are in RTOs[414] which engage in planning across the RTO, balancing supply and demand in real time throughout the RTO. Accordingly, generating resources in one part of the RTO such as a coal generator can serve load in other parts of the RTO, as well as load outside of the RTO. As we consider each of these geographic areas in the Geographic Availability TSD, we make key points as to why this final rule does not negatively impact the ability of these regions to access new coal generation to the extent that coal is needed to supply demand and/or those regions want to include new coal-fired generation in their resource mix.

N. Final Requirements for Disposition of Captured CO_2

This section discusses the different regulatory components, already in place, that assure the safety and effectiveness of GS. This section, by demonstrating that GS is already covered by an effective regulatory structure, complements the analysis of the technical feasibility of GS contained in Sec. V.M. Together, these sections affirm that the technical feasibility of GS is adequately demonstrated.

In 2010, the EPA finalized an effective and coherent regulatory framework to ensure the long-term, secure and safe storage of large volumes of CO_2. The EPA developed these Underground Injection Control (UIC) Class VI well regulations under authority of the Safe Drinking Water Act (SDWA) to facilitate injection of CO_2 for GS, while protecting human health and the environment by ensuring the protection of underground sources of drinking water (USDWs). The Class VI regulations are built upon 35 years of federal experience regulating underground injection wells, and many additional years of state UIC program expertise. The EPA and states have decades of UIC experience with the Class II program, which provides a regulatory framework for the protection of USDWs for CO_2 injected for purposes of EOR.

In addition, to complement both the Class VI and Class II rules, the EPA used CAA authority to develop air-side monitoring and reporting requirements for CO_2 capture, underground injection, and geologic sequestration through the GHGRP. Information collected under the GHGRP provides a transparent means for the EPA and the public to continue to evaluate the effectiveness of GS.

As explained below, these requirements help ensure that sequestered CO_2 will remain in place, and, using SDWA and CAA authorities, provide the monitoring mechanisms to identify and address potential leakage. We note the near consensus in the public responses to the Class VI rulemaking that saline and oil and gas reservoirs provide ready means for secure GS of CO_2.[415]

1. Requirements for UIC Class VI and Class II Wells

Under SDWA, the EPA developed the UIC Program to regulate the underground injection of fluids in a manner that ensures protection of USDWs. UIC regulations establish six different well classes that manage a range of injectates (*e.g.,* industrial and municipal wastes; fluids associated with oil and gas activities; solution mining fluids; and CO_2 for geologic sequestration) and which accommodate varying geologic, hydrogeological, and other conditions. The standards apply to injection into any type of formation that meets the rule's rigorous criteria, and so apply not only to injection into deep

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[412] The NETL cost estimates for CO_2 transport assume a pipeline of 100 kilometers. NETL (2015) at p. 44.

[413] The data in Figure 1 is based on estimates compiled by the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB) and published in the United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition. As discussed in the TSD, deep saline formation potential was not assessed for Alaska, Connecticut, Hawaii, Massachusetts, Nevada, Rhode Island, and Vermont. Oil and gas storage potential was not assessed for Alaska, Washington, Nevada, and Oregon. Unmineable coal seams were not assessed for Nevada, Oregon, California, Idaho, and New York. We are assuming for purposes of our analysis here that they do not have storage potential in those formations.

[414] In this discussion, we use the term RTO to indicate both ISOs and RTOs.

[415] In that rulemaking, we stated that ''most commenters encouraged the EPA not to automatically exclude any potential injection formations for GS at this stage of deployment.'' We added that commenters suggested, in particular, ''that there is sufficient technical basis and scientific evidence to allow GS in depleted oil and gas reservoirs and in saline formations, noting that there is consensus on how to inject into these formation types.'' 75 FR at 77252 (Dec. 10, 2010).

saline formations, but also can apply to injection into unmineable coal seams and other formations. See 75 FR 77256 (Dec. 10, 2010).

The EPA's UIC regulations define the term USDWs to include current and future sources of drinking water and aquifers that contain a sufficient quantity of ground water to supply a public water system, where formation fluids either are currently being used for human consumption or that contain less than 10,000 ppm total dissolved solids.[416] UIC requirements have been in place for over three decades and have been used by the EPA and states to manage hundreds of thousands of injection wells nationwide.

a. Class VI Requirements

In 2010, the EPA established a new class of well, Class VI. Class VI wells are used to inject CO_2 into the subsurface for the purpose of long-term sequestration. See 75 FR 77230 (Dec. 10, 2010). This rule accounts for the unique nature of CO_2 injection for large-scale GS. Specifically, the EPA addressed the unique characteristics of CO_2 injection for GS including the large CO_2 injection volumes anticipated at GS projects, relative buoyancy of CO_2, its mobility within subsurface geologic formations, and its corrosivity in the presence of water. The UIC Class VI rule was developed to facilitate GS and ensure protection of USDWs from the particular risks that may be posed by large scale CO_2 injection for purposes of long-term GS. The Class VI rule establishes technical requirements for the permitting, geologic site characterization, area of review (*i.e.,* the project area) and corrective action, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care, site closure, and financial responsibility for the purpose of protecting USDWs.[417] Notably:

Site characterization includes assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of a proposed GS site to ensure that Class VI wells are sited in appropriate locations and CO_2 streams are injected into suitable formations with a confining zone or zones free of transmissive faults or fractures to ensure USDW protection.[418] [419] Site characterization is designed to eliminate unacceptable sites that may pose risks to USDWs. Generally, injection of CO_2 for GS should occur beneath the lowermost formation containing a USDW.[420] To increase the availability of Class VI sites in geographic areas with very deep USDWs, waivers from the injection depth requirements may be sought where owners or operators can demonstrate USDW protection.[421]

Owners or operators of Class VI wells must delineate the project area of review using computational modeling that accounts for the physical and chemical properties of the injected CO_2 and displaced fluids and is based on an iterative process of available site characterization, monitoring, and operational data.[422] Within the area of review, owners or operators must identify and evaluate all artificial penetrations to identify those that need corrective action to prevent the movement of CO_2 or other fluids into or between USDWs.[423] [424] Due to the potentially large size of the area of review for Class VI wells, corrective actions may be conducted on a phased basis during the lifetime of the project.[425] Periodic reevaluation of the area of review is required and enables owners or operators to incorporate previously collected monitoring and operational data to verify that the CO_2 plume and the associated area of elevated pressure are moving as predicted within the subsurface.[426]

Well construction must use materials that can withstand contact with CO_2 over the operational and post-injection life of the project.[427] These requirements address the unique physical characteristics of CO_2, including its buoyancy relative to other fluids in the subsurface and its potential corrosivity in the presence of water.

Requirements for operation of Class VI injection wells account for the unique conditions that will occur during large-scale GS including buoyancy, corrosivity, and high sustained pressures over long periods of operation.[428] [429]

Owners or operators of Class VI wells must develop and implement a comprehensive testing and monitoring plan for their projects that includes injectate analysis, mechanical integrity testing, corrosion monitoring, ground water and geochemical monitoring, pressure fall-off testing, CO_2 plume and pressure front monitoring and tracking, and, at the discretion of the Class VI director, surface air and/or soil gas monitoring.[430] Owners and operators must periodically review the testing and monitoring plan to incorporate operational and monitoring data and the most recent area of review reevaluation.[431] Robust monitoring of the CO_2 stream, injection pressures, integrity of the injection well, ground water quality and geochemistry, and monitoring of the CO_2 plume and position of the pressure front throughout injection will ensure protection of USDWs from endangerment, preserve water quality, and allow for timely detection of any leakage of CO_2 or displaced formation fluids.

Although subsurface monitoring is the primary and effective means of determining if there are any risks to a USDW, the Class VI rule also authorizes the UIC Program Director to require surface air and/or soil gas monitoring on a site-specific basis. For example, the Class VI Director may require surface air/soil gas monitoring of the flux of CO_2 out of the subsurface, with elevation of CO_2 levels above background serving as

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[416] 40 CFR 144.3.

[417] The Class VI rule rests on a robust technical and scientific foundation, reflecting scientific oversight and peer review. In developing these Class VI rules, the EPA engaged with the SAB, providing detailed information on key issues relating to geologic sequestration—including monitoring schemes; methods to predict and verify capacity, injectivity, and effectiveness of subsurface CO_2 storage; and characterization and management of risks associated with plume migration and pressure increases in the subsurface. See: *http://yosemite.epa.gov/sab/sabproduct.nsf/0/AD09B42B75D9E36D85257704004882CF?OpenDocument.* In addition, the EPA developed a peer reviewed Vulnerability Evaluation Framework, which served as a technical support document for both the Class VI and Subpart RR rules. See: *http://www.epa.gov/climatechange/Downloads/ghgemissions/VEF-Technical_Document_072408.pdf.* In the section 111(b) rulemaking here, the SAB Work Group, in a letter endorsed by the full SAB Committee, found that ''while the scientific and technical basis for carbon storage provisions is new and emerging science, the agency is using the best available science and has conducted peer review at a level required by agency guidance.'' Memorandum of Jan. 7, 2014, from SAB Work Group Chair to Members of the Chartered SAB and SAB Liaisons, p. 3. The letter was subsequently endorsed by the full SAB. Work Group Letter of Jan. 24, 2014, as edited by the full Committee.

[418] 75 FR 77240 and 75 FR 77247 (December 10, 2010).

[419] 40 CFR 146.82 and 146.83. Comments indicating that EPA rules have not considered issues of exposure pathways such as abandoned wells or formation fissures are mistaken. (See, *e.g.,* Comments of UARG, p. 52 (Docket entry: EPA–HQ–OAR–2013–0495–9666).)

[420] 40 CFR 146.81(d).

[421] 40 CFR 146.95.

[422] 40 CFR 146.84(a).

[423] 40 CFR 146.84(c)(1)(3) and 146.90(d)(1).

[424] 40 CFR 146.81(d) and 146.84.

[425] 40 CFR 146.84(b)(2)(iv).

[426] 40 CFR 146.84(e)(1).

[427] 40 CFR 146.86(b).

[428] 75 FR 77250–52 (December 10, 2010); see also id. at 77234–35. Commenters were mistaken in asserting (without reference to Class VI provisions) that the EPA had ignored issues relating to CO_2 properties when injected in large volumes in supercritical state into geologic formations.

[429] 40 CFR 146.88.

[430] 40 CFR 146.90.

[431] 40 CFR 146.90(j).

an indicator of potential leakage and USDW endangerment.[432]

Class VI well owners or operators must develop and update a site-specific, comprehensive emergency and remedial response plan that describes actions to be taken (*e.g.,* cease injection) to address potential events that may cause endangerment to a USDW during the construction, operation, and post-injection site care periods of the project.[433]

Financial responsibility demonstrations are required to ensure that funds will be available for all area of review corrective action, injection well plugging, post-injection site care, site closure, and emergency and remedial response.[434]

Following cessation of injection, the operator must conduct comprehensive post-injection site care activities to show the position of the CO_2 plume and the associated area of elevated pressure to demonstrate that neither poses an endangerment to USDWs.[435] The injection well also must be plugged, and following a demonstration of non-endangerment of USDWs by the Class VI owner or operator, the site must be closed.[436] [437] The default duration for the post-injection site care period is 50 years, with flexibility for demonstrating that an alternative period is appropriate if it ensures non-endangerment of USDWs.[438] Following successful closure, the facility property deed must record that the underlying land is used for GS.[439]

The EPA has completed technical guidance documents on Class VI well site characterization, area of review and corrective action, well testing and monitoring, project plan development, well construction, and financial responsibility.[440] [441] [442] [443] [444] [445] The EPA has also issued guidance documents on transitioning Class II wells to Class VI wells; well plugging, post-injection site care, and site closure; and recordkeeping, reporting, and data management.[446] [447] [448] [449]

To inform the development of the UIC Class VI rule, the EPA solicited stakeholder input and reviewed ongoing domestic and international GS research, demonstration, and deployment projects. The EPA also leveraged injection experience of the UIC Program, such as injection via Class II wells for EOR. A description of the work conducted by the EPA in support of the UIC Class VI rule can be found in the preamble for the final rule (see 75 FR 77230 and 77237–240(December 10, 2010)).

The EPA has issued Class VI permits for six wells under two projects. In September 2014, a UIC Class VI injection well permit (to construct) was issued by the EPA to Archer Daniels Midland for an ethanol facility in Decatur, Illinois. The goal of the project is to demonstrate the ability of the Mount Simon geologic formation, a deep saline formation, to accept and retain industrial scale volumes of CO_2 for permanent GS. The permitted well has a projected operational period of five years, during which time 5.5 million metric tons of CO_2 will be injected into an area of review with a radius of approximately 2 miles.[450] Following the operational period, Archer Daniels Midland plans a post-injection site care period of ten years.[451] In September 2014, the EPA also issued four Class VI injection well permits (to construct) to the FutureGen Industrial Alliance project in Jacksonville, Illinois, which proposed to capture CO_2 emissions from a coal-fired power plant in Meredosia, Illinois and transport the CO_2 by pipeline approximately 30 miles to the deep saline GS site.[452] The Alliance proposed to inject a total of 22 million metric tons of CO_2 into an area of review with a radius of approximately 24 miles over the 20-year life of the project, with a post-injection site care period of fifty years.[453]

Both permit applicants addressed siting and operational aspects of GS (including issues relating to volumes of the CO_2 and nature of the CO_2 injectate), and included monitoring that helps provide assurance that CO_2 will not migrate to shallower formations. The permits were based on findings that regional and local features at the site allow the site to receive injected CO_2 in specified amounts without buildup of pressure which would create faults or fractures, and further, that monitoring provides early warning of any changes to groundwater or CO_2 leakage.[454]

The permitting of these projects illustrates that permit applicants were able to address perceived challenges to issuance of Class VI permits. These permits demonstrate that these projects are capable of safely and securely sequestering large volumes of CO_2—including from steam generating units—for long-term storage since the EPA would not otherwise have issued the permits.

b. Class II Requirements

As explained in Section M.3 above, CO_2 has been injected into the subsurface via injection wells for EOR, boosting production efficiency by re-pressurizing oil and gas reservoirs and increasing the mobility of oil. There are decades of industry experience in operating EOR projects. The CO_2 injection wells used for EOR are regulated through the UIC Class II program.[455] CO_2 storage associated with Class II wells is a common occurrence and CO_2 can be safely stored where injected through Class II-permitted wells for the purpose of enhanced oil or gas-related recovery.

UIC Class II regulations issued under section 1421 of SDWA provide minimum federal requirements for site characterization, area of review, well construction (*e.g.,* casing and cementing), well operation (*e.g.,* injection pressure), injectate sampling, mechanical integrity testing, plugging and abandonment, financial responsibility, and reporting. Class II wells must undergo periodic mechanical integrity testing which will detect well construction and operational

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[432] 40 CFR 146.90(h)(1) and 75 FR at 77259 (Dec. 10, 2010).

[433] 40 CFR 146.94.

[434] 40 CFR 146.85.

[435] 40 CFR 146.93.

[436] 40 CFR 146.92.

[437] 40 CFR 146.93.

[438] 40 CFR 146.93(b).

[439] 40 CFR 146.93(c).

[440] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r13004.pdf.*

[441] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r13005.pdf.*

[442] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r13001.pdf.*

[443] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r11017.pdf.*

[444] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r11020.pdf.*

[445] *http://water.epa.gov/type/groundwater/uic/class6/upload/uicfinancialresponsibilityguidancefinal072011v.pdf.*

[446] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13004.pdf.* See also 40 CFR 144.19 and ''Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil Recovery or Gas Recovery Wells to Class VI'', April 23, 2015, Available at: *http://water.epa.gov/type/groundwater/uic/class6/upload/class2eorclass6memo.pdf.*

[447] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13005.pdf.*

[448] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13001.pdf.*

[449] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13002.pdf.*

[450] *http://www.epa.gov/region5/water/uic/adm/.* In addition, Archer Daniels Midland received a UIC Class VI injection well permit for a second well in December 2014. Archer Daniels Midland had been injecting CO_2 at this well since 2011 under a UIC Class I permit issued by the Illinois EPA.

[451] *http://www.epa.gov/region5/water/uic/adm/.*

[452] After permit issuance, and for reasons unrelated to the permitting proceeding, DOE initiated a structured closeout of federal support for the FutureGen project in February 2015. However, these are still active Class VI permits.

[453] *http://www.epa.gov/r5water/uic/futuregen/.*

[454] *http://www.epa.gov/r5water/uic/futuregen/; http://www.epa.gov/region5/water/uic/adm/.*

[455] 40 CFR 144.6(b).

conditions that could lead to loss of injectate and migration into USDWs.

Section 1425 of SDWA allows states to demonstrate that their program is effective in preventing endangerment of USDWs. These programs must include permitting, inspection, monitoring, record-keeping, and reporting components.

2. Relevant Requirements of the GHGRP

The GHGRP requires reporting of facility-level GHG data and other relevant information from large sources and suppliers in the United States. The final rules under 40 CFR part 60 specifically require that if an affected EGU captures CO_2 to meet the applicable emissions limit, the EGU must report in accordance with 40 CFR part 98, subpart PP (Suppliers of Carbon Dioxide) and the captured CO_2 must be injected at a facility or facilities that reports in accordance with 40 CFR part 98, subpart RR (Geologic Sequestration of Carbon Dioxide). See § 60.5555(f). Taken together, these requirements ensure that the amount of captured and sequestered CO_2 will be tracked as appropriate at project- and national-levels, and that the status of the CO_2 in its sequestration site will be monitored, including air-side monitoring and reporting.

Specifically, subpart PP provides requirements to account for CO_2 supplied to the economy. This subpart requires affected facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground to report the mass of CO_2 captured and supplied to the economy.[456] CO_2 suppliers are required to report the annual quantity of CO_2 transferred offsite and its end use, including GS.[457]

This rule finalizes amendments to subpart PP reporting requirements, specifically requiring that the following pieces of information be reported: (1) the electronic GHG Reporting Tool identification (e–GGRT ID) of the EGU facility from which CO_2 was captured, and (2) the e–GGRT ID(s) for, and mass of CO_2 transferred to, each GS site reporting under subpart RR.[458]

As noted, this final rule also requires that any affected EGU unit that captures CO_2 to meet the applicable emissions limit must transfer the captured CO_2 to a facility that reports under GHGRP subpart RR. In order to provide clarity on this requirement, the EPA reworded the proposed language under § 60.5555(f) to use the phrase ''If your affected unit captures CO_2'' in place of the phrase ''If your affected unit employs geologic sequestration''. This revision is not a change from the EPA's initial intent.

Reporting under subpart RR is required for all facilities that have received a Class VI UIC permit for injection of CO_2.[459] Subpart RR requires facilities meeting the source category definition (40 CFR 98.440) for any well or group of wells to report basic information on the mass of CO_2 received for injection; develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; report the mass of CO_2 sequestered using a mass balance approach; and report annual monitoring activities.[460] [461] [462] [463] Although deep subsurface monitoring is the primary and effective means of determining if there are any leaks to a USDW, the monitoring employed under a subpart RR MRV Plan can be utilized, if required by the UIC Program Director, to further ensure protection of USDWs.[464] The subpart RR MRV plan includes five major components:

A delineation of monitoring areas based on the CO_2 plume location. Monitoring may be phased in over time.[465]

An identification and evaluation of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways. The monitoring program will be designed to address the risks identified.[466]

A strategy for detecting and quantifying any surface leakage of CO_2 in the event leakage occurs. Multiple monitoring methods and accounting techniques can be used to address changes in plume size and risks over time.[467]

An approach for establishing the expected baselines for monitoring CO_2 surface leakage. Baseline data represent pre-injection site conditions and are used to identify potential anomalies in monitoring data.[468]

A summary of considerations made to calculate site-specific variables for the mass balance equation. Site-specific variables may include calculating CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment, and considerations for calculating CO_2 from produced fluids.[469]

Subpart RR provides a nationally consistent mass balance framework for reporting the mass of CO_2 that is sequestered. Certain monitoring and operational data for a GS site is required to be reported to the EPA annually. More information on the MRV plan and annual reporting is available in the subpart RR final rule (75 FR 75065; December 1, 2010) and its associated technical support document.[470]

Under this final rule, any well receiving CO_2 captured from an affected EGU, be it a Class VI or Class II well, must report under subpart RR.[471] As explained below in Section V.N.5.a, a Class II well's UIC regulatory status does not change because it receives such CO_2. Nor does it change by virtue of reporting under subpart RR.

3. UIC and GHGRP Rules Provide Assurance To Prevent, Monitor, and Address Releases of Sequestered CO_2 to Air

Together the requirements of the UIC and GHGRP programs help ensure that sequestered CO_2 will remain secure, and provide the monitoring mechanisms to identify and address potential leakage using SDWA and CAA authorities. The EPA designed the GHGRP subpart RR requirements for GS with consideration of UIC requirements. The monitoring required by GHGRP subpart RR is complementary to and builds on UIC monitoring and testing requirements. 75 FR 77263. Although the regulations for Class VI and Class II injection wells are designed to ensure protection of USDWs from endangerment the practical effect of these complementary technical requirements, as explained below, is that they also prevent releases of CO_2 to the atmosphere.

The UIC and GHGRP programs are built upon an understanding of the mechanisms by which CO_2 is retained in geologic formations, which are well understood and proven.

Structural and stratigraphic trapping is a physical trapping mechanism that occurs when the CO_2 reaches a stratigraphic zone with low permeability (*i.e.,* geologic confining

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[456] 40 CFR 98.420(a)(1).

[457] 40 CFR 98.426.

[458] 40 CFR 98.426(h).

[459] 40 CFR 98.440.

[460] 40 CFR 98.446.

[461] 40 CFR 98.448.

[462] 40 CFR 98.446(f)(9) and (10).

[463] 40 CFR 98.446(f)(12).

[464] See 75 FR at 77263 (Dec. 10, 2010).

[465] 40 CFR 98.448(a)(1).

[466] 40 CFR 98.448(a)(2).

[467] 40 CFR 98.448(a)(3).

[468] 40 CFR 98.448(a)(4).

[469] 40 CFR 98.448(a)(5).

[470] Technical Support Document: ''General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Subparts RR and UU'' (Docket EPA–HQ–OAR–2009–0926), November 2010.

[471] See § 60.5555(f).

system) that prevents further upward migration.

Residual trapping is a physical trapping mechanism that occurs as residual CO_2 is immobilized in formation pore spaces as disconnected droplets or bubbles at the trailing edge of the plume due to capillary forces.

Adsorption trapping is another physical trapping mechanism that occurs when CO_2 molecules attach to the surfaces of coal and certain organic rich shales, displacing other molecules such as methane.

Solubility trapping is a geochemical trapping mechanism where a portion of the CO_2 from the pure fluid phase dissolves into native ground water and hydrocarbons.

Mineral trapping is a geochemical trapping mechanism that occurs when chemical reactions between the dissolved CO_2 and minerals in the formation lead to the precipitation of solid carbonate minerals.

a. Class VI Wells

As just discussed in Section V.N.1, the UIC Class VI rule provides a framework to ensure the safety of underground injection of CO_2 such that USDWs are not endangered. As explained below, protection against releases to USDWs likewise assures against releases to ambient air. Through the injection well permit application process, the Class VI permit applicant (*i.e.,* a prospective Class VI well owner or operator) must demonstrate that the injected CO_2 will be trapped and retained in the geologic formation, and not migrate out of the injection zone or the approved project area (*i.e.,* the area of review). To assure that CO_2 is confined within the injection zone, major components to be considered and included in Class VI permits are site characterization, area of review delineation and corrective action, well construction and operation, testing and monitoring, financial responsibility, post-injection site care, well plugging, emergency and remedial response, and site closure as described in Section V.N.1.

Site characterization provides the foundation for successful GS projects. It includes evaluation of the chemical and physical mechanisms that will occur in the subsurface to immobilize and securely store the CO_2 within the injection zone over the long-term (see above). Site characterization requires a detailed assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed GS site to ensure that wells are sited in suitable locations.[472] Data and information collected during site characterization are used in the development of injection well construction and operating plans; provide inputs for modeling the extent of the injected CO_2 plume and related pressure front; and establish baseline information to which geochemical, geophysical, and hydrogeologic site monitoring data collected over the life of the injection project can be compared.

The Class VI rules contain rigorous subsurface monitoring requirements to assure that the chosen site is functioning as characterized. This subsurface monitoring should detect leakage of CO_2 before CO_2 would reach the atmosphere. For example, when USDWs are present, they are generally located above the injection zone. If CO_2 were to reach a USDW prior to being released to the atmosphere, the presence of CO_2 or geochemical changes that would be caused by CO_2 migration into unauthorized zones would be detected by a UIC Class VI monitoring program that is approved and periodically evaluated/adjusted based on permit conditions.

Likewise, UIC Class VI mechanical integrity testing requirements are designed to confirm that a well maintains internal and external mechanical integrity. Continuous monitoring of the internal mechanical integrity of Class VI wells ensures that injection wells maintain integrity and serves as a way to detect problems with the well system. Mechanical integrity testing provides an early indication of potential issues that could lead to CO_2 leakage from the confining zone, providing assurance and verification that CO_2 will not reach the atmosphere.

Further assurance is provided by the regulatory requirement that injection must cease if there is evidence that the injected CO_2 and/or associated pressure front may cause endangerment to a USDW.[473] Once the anomalous operating conditions are verified, the cessation of injection, as required by UIC permits, will minimize any risk of release to air.

Following cessation of injection, the operator must conduct comprehensive post-injection site care to show the position of the CO_2 plume and the associated area of elevated pressure to demonstrate that neither poses an endangerment to USDWs—also having the practical effect of preventing releases of CO_2 to the atmosphere. Post-injection site care includes appropriate monitoring and other needed actions (including corrective action). The default duration for the post-injection site care period is 50 years, with flexibility for demonstrating that an alternative period is appropriate if it ensures non-endangerment of USDWs.

As the EPA has found, the UIC Class VI injection well requirements protect against releases from all exposure pathways. Specifically, the EPA stated that the Class VI rules ''[are] specifically designed to ensure that the CO_2 (and any incidental associated substances derived from the source materials and the capture process) will be isolated within the injection zone.'' The EPA further stated that ''[t]he EPA concluded that the elimination of exposure routes through these requirements, which are implemented through a SDWA UIC permit, will ensure protection of human health and the environment. . .''.[474]

GHGRP subpart RR complements these UIC Class VI requirements. Requirements under the UIC program are focused on demonstrating that USDWs are not endangered as a result of CO_2 injection into the subsurface, while requirements under the GHGRP through subpart RR enable accounting for CO_2 that is geologically sequestered. A methodology to account for potential leakage is developed as part of the subpart RR MRV plan (see Section V.N.2). The MRV plan submitted for subpart RR may describe (or provide by reference to the UIC permit) the relevant elements of the UIC permit (*e.g.* assessment of leakage pathways in the monitoring area) and how those elements satisfy the subpart RR requirements. The MRV plan required under subpart RR may rely upon the knowledge of the subsurface location of CO_2 and site characteristics that are developed in the permit application process, and operational monitoring results for UIC Class VI permitted wells.

In summary, there are well-recognized physical mechanisms for storing CO_2 securely. The comprehensive and rigorous site characterization requirements of the Class VI rules assure that sites with these properties are selected. Subsurface monitoring serves to assure that the sequestration site operates as intended, and this monitoring continues through a post-closure period. Although release of CO_2 to air is unlikely and should be detected prior to release by subsurface monitoring, the subpart RR air-side monitoring and reporting regime

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[472] 40 CFR 146.82(a) and (c).

[473] 40 CFR 146.94(b).

[474] 79 FR at 353 (January 3, 2014) (Final Hazardous Waste Management System: Conditional Exclusion for Carbon Dioxide (CO_2) Streams in Geologic Sequestration Activities under subtitle C of RCRA). See Section N.5.c below.

provides back up assurance that sequestered CO_2 has not been released to the atmosphere.

b. Class II Wells

The Class II rules likewise are designed to protect USDWs during EOR operation, including the injection of CO_2 for EOR. For example, UIC Class II minimum federal requirements promulgated under SDWA address site characterization, area of review, well construction (*e.g.,* casing and cementing), well operation (*e.g.,* injection pressure), injectate sampling, mechanical integrity testing, plugging and abandonment, financial responsibility, and reporting. Class II wells must undergo periodic mechanical integrity testing which will detect well construction and operational conditions that could lead to loss of injectate and migration into USDWs. The establishment of maximum injection pressures, designed to ensure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the confining zone, prevents injection from causing the movement of fluids into an underground source of drinking water. The safeguards that protect USDWs also serve as an early warning mechanism for releases of CO_2 to the atmosphere.

CO_2 injected via Class II wells becomes sequestered by the trapping mechanisms described above in this Section V.N.3. As with Class VI wells, for Class II wells that report under subpart RR, there is monitoring to evaluate whether CO_2 used for EOR will remain safely in place both during and after the injection period. Subpart RR provides a CO_2 accounting framework that will enable the EPA to assess both the project-level and national efficacy of geologic sequestration to determine whether additional requirements are necessary and, if so, inform the design of such regulations.

c. Response to Comments

Commenters maintained that GS was not demonstrated for CO_2 captured from EGUs. In addition, commenters noted that the volumes of captured CO_2 would be considerably larger than from existing GS sites, and could quadruple amounts injected into Class II EOR wells. In addition to volumes of CO_2 to be injected, commenters opined on the possibility of sporadic CO_2 supply due to the nature of EGU operation.[475]

The EPA does not agree. CO_2 capture from EGUs is demonstrated as discussed in Sections V.D and V.E. As discussed below, the volumes of CO_2 are comparable to the amounts that have been injected at large scale commercial operations. The EPA also disagrees that the volume of CO_2 would quadruple amounts injected into Class II EOR wells because CO_2 may be sequestered in deep saline formations, which have widespread geographic availability (see Section M.1). The BSER determination and regulatory impact analysis for this rule relies on GS in deep saline formations.[476] However, the EPA also recognizes the potential for sequestering CO_2 via EOR and allows the use of EOR as a compliance option. According to data reported to the GHGRP, approximately 60 million metric tons of CO_2 were supplied to EOR in the United States in 2013.[477] Approximately 70 percent of total CO_2 supplied in the United States was produced from geologic (natural) CO_2 sources and approximately 30 percent was captured from anthropogenic sources. CO_2 pipeline systems, such as those serving the Permian Basin, have multiple sources of CO_2 that serve to levelize the pipeline supply, thus minimizing the effect of supply on the EOR operator.

GS of anthropogenic CO_2 in deep saline formations is demonstrated. First, as explained above, the EPA has issued construction permits under the Class VI program. It would not have done so, and under the regulations cannot have done so, without demonstrations that CO_2 would be securely confined. One of these projects was for a steam generating EGU.

Second, international experience with large scale commercial GS projects has demonstrated through extensive monitoring programs that large volumes of CO_2 can be safely injected and securely sequestered for long periods of time at volumes and rates consistent with those expected under this rule. This experience has also demonstrated the value and efficacy of monitoring programs to determine the location of CO_2 in the subsurface and detect potential leakage through the presence of CO_2 in the shallow subsurface, near surface and air.

The Sleipner CO_2 Storage Project is located at an offshore gas field in the North Sea where CO_2 must be removed from the natural gas in order to meet customer requirements and reduce costs. The project began injecting CO_2 into the deep subsurface in 1996. The single offshore injection well injects approximately 1 million metric tons per year into a thick, permeable sandstone above the gas producing zone. Approximately 15 million metric tons of CO_2 have been injected since inception. Many US and international organizations have conducted monitoring at Sleipner. The location and dimensions of the CO_2 plume have been measured numerous times using 3-dimensional seismic monitoring since the 1994 pre-injection survey. The monitoring data have demonstrated that although the plume is behaving differently than initially modeled due to thin layers of impermeable shale that were not initially identified in the reservoir model, the CO_2 remains trapped in the injection zone. Numerous other techniques have been successfully used to monitor CO_2 storage at Sleipner. The research and monitoring at Sleipner demonstrates the value of a comprehensive approach to site characterization, computational modeling and monitoring, as is required under UIC Class VI rules. The experience at Sleipner demonstrates that large volumes of CO_2, of the same order of magnitude expected for an EGU, can be safely injected and stored in saline reservoirs over an extended period.

Snøhvit is another large offshore CO_2 storage project, located at a gas field in the Barents Sea. Like Sleipner the natural gas must be treated to reduce high levels of CO_2 to meet processing standards and reduce costs. Gas is transported via pipeline 95 miles to a gas processing and liquefied natural gas plant and the CO_2 is piped back offshore for injection. Approximately 0.7 million metric tons per year CO_2 are injected into permeable sandstone below the gas reservoir. Between 2008 and 2011, the operator observed pressure increases in the injection formation (Tubaen Formation) greater than expected and conducted time lapse seismic surveys and studies of the injection zone and concluded that the pressure increase was mainly caused by a limited storage capacity in the formation.[478] In 2011,

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[475] See, *e.g.* Comments of Southern Company, p. 41 (Docket entry: EPA–HQ–OAR–2013–0495–10095).

[476] The EPA anticipates EOR projects may be early GS projects because these formations have been previously well characterized for hydrocarbon recovery, likely already have suitable infrastructure (*e.g.,* wells, pipelines, etc.), and have an associated economic benefit of oil production.

[477] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

[478] Grude, S. M. Landrøa, and J. Dvorkinb, 2014, Pressure effects caused by CO_2 injection in the Tubåen Fm., the Snøhvit field. International Journal of Greenhouse Gas Control 27 (2014) 178–187. Commenters argued that the project had failed to sequester CO_2, referring to the initial cessation of injection. See, *e.g.* Comments of UARG p. 56 (Docket entry: EPA–HQ–OAR–2013–0495–9666). In fact, injection resumed successfully, as described in the text above.

the injection well was modified and injection was initiated in a second interval (Stø Formation) in the field to increase the storage capacity. Approximately 3 million metric tons of CO_2 have been injected since 2008. Monitoring demonstrates that no leakage has occurred, again demonstrating that large volumes of CO_2, of the same order of magnitude expected for an EGU, can be safely injected and stored in deep saline formations over an extended period.

As discussed above in Sections V.E.2.a and M, CO_2 from the Great Plains Synfuels plant in North Dakota has been injected into the Weyburn oil field in Saskatchewan Canada since 2000. Over that time period the project has injected more than 16 million metric tons of CO_2. It is anticipated that approximately 40 million metric tons of CO_2 will be permanently sequestered over the lifespan of the project. Extensive monitoring by U.S. and international partners has demonstrated that no leakage has occurred. The sources of CO_2 for EOR may vary (*e.g.,* industrial processes, power generation); however, this does not impact the effectiveness of EOR operations (see Section V.M.3).

CO_2 used for EOR may come from anthropogenic or natural sources. The source of the CO_2 does not impact the effectiveness of the EOR operation. CO_2 capture, treatment and processing steps provide a concentrated stream of CO_2 in order to meet the needs of the intended end use. CO_2 pipeline specifications of the U.S. Department of Transportation Pipeline Hazardous Materials Safety Administration found at 49 CFR part 195 (Transportation of Hazardous Liquids by Pipeline) apply regardless of the source of the CO_2 and take into account CO_2 composition, impurities, and phase behavior. Additionally, EOR operators and transport companies have specifications to ensure related to the composition of CO_2. These requirements and specifications ensure EOR operators receive a known and consistent CO_2 stream.

At the In Salah CO_2 storage project in Algeria, CO_2 is removed from natural gas produced at three nearby gas fields in order to meet export quality specification. The CO_2 is transported by pipeline approximately 3 miles to the injection site. Three horizontal wells are used to inject the CO_2 into the down-dip aquifer leg of the gas reservoir approximately 6,200 feet deep. Between 2004 and 2011 over 3.8 million metric tons of CO_2 were stored. Injection rates in 2010 and 2011 were approximately 1 million metric tons per year. Storage integrity has been monitored by several U.S. and international organizations and the monitoring program has employed a wide range of geophysical and geochemical methods, including time lapse seismic, microseismic, wellhead sampling, tracers, down-hole logging, core analysis, surface gas monitoring, groundwater aquifer monitoring and satellite data. The data have been used to support periodic risk assessments during the operational phase of the project. In 2010 new data from seismic, satellite and geomechanical models were used to inform the risk assessment and led to the decision to reduce CO_2 injection pressures due to risk of vertical leakage into the lower caprock, and risk of loss of well integrity. The caprock at the site consisted of main caprock units, providing the primary seal, and lower caprock units, providing additional buffers. There was no leakage from the well or through the caprock, but the risk analysis identified an increased risk of leakage, therefore, the aforementioned precautions were taken. Additional analysis of the reservoir, seismic and geomechanical data led to the decision to suspend CO_2 injection in June 2011. No leakage has occurred and the injected CO_2 remains safely stored in the subsurface. The decision to proceed with safe shutdown of injection resulted from the analysis of seismic and geomechanical data to identify and respond to storage site risk. The In Salah project demonstrates the value of developing an integrated and comprehensive set of baseline site data prior to the start of injection, and the importance of regular review of monitoring data. Commenters also noted that the data collection and analysis had proven effective at preventing any release of sequestered CO_2 to either underground drinking water sources or to the atmosphere.[479]

These projects demonstrate that sequestration of CO_2 captured from industrial operations has been successfully conducted on a large scale and over relatively long periods of time. The volumes of captured CO_2 are within the same order of magnitude as that expected from EGUs. Even though potentially adverse conditions were identified at some projects (In Salah and Snøhvit), there were no releases to air and the monitoring systems were effective in identifying the issues in a timely manner, and these issues were addressed effectively. In each case, the site-specific characteristics were evaluated on a case-by-case basis to select a site where the geologic conditions are suitable to ensure long-term, safe storage of CO_2. Each project was designed to address the site-specific characteristics and operated to successfully inject CO_2 for safe storage.

4. Must the standard of performance for CO_2 include CAA requirements on the sequestration site?

One commenter maintained as a matter of law that a standard predicated on use of CCS is not a ''system of emission reduction'', and therefore is not a ''standard of performance'' within the meaning of section 111 (a)(1) of the Act. The commenter argued that the standard does not require sequestration of captured CO_2 but only capture, so that no emission reductions are associated with the standard. A gloss on this argument is that there are no enforceable requirements for the captured CO_2 (''[t]he fate of that [captured] CO_2 is something that the proposed standard does not proscribe with enforceable requirements''). The commenter further argues that a ''system of emission reduction'' under section 111 must be ''designed into the new source *itself''* so that off-site underground sequestration of captured CO_2 emissions ''could never satisfy the statutory requirements governing a 'standard of performance''' (emphasis original).[480]

The EPA disagrees with both the legal and factual assertions in this comment. As to the legal point, the commenter fails to distinguish capture and sequestration of carbon from every other section 111 standard which is predicated on capture of a pollutant. Indeed, all emission standards not predicated on outright pollutant destruction involve capture of the pollutant and its subsequent disposition in the capturing medium. Thus, metals are captured in devices like baghouses or scrubbers, leaving a solid waste or wastewater to be managed. Gases can be captured with activated carbon or under pressure, again requiring further management of the captured pollutant(s). The EPA is required to consider these potential implications in promulgating an NSPS. See section 111(a)(1) (in promulgating a standard of performance under section 111, the EPA must ''tak[e] into account . . . any nonair quality health and environmental

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[479] ''It is important to note that although the In Salah project is no longer injecting CO_2, the CCS community still views this early saline project as a success because the monitoring program served its intended purpose. That is, the monitoring methods deployed at this site informed the operator of a potential problem, leading to a shutdown of CO_2 injection before the Caprock was breached.'' Comment of EPRI, p. 14 Docket entry: EPA–HQ–OAR–2013–0495–8925).

[480] Comments of UARG, pp. 37–38 (Docket entry: EPA–HQ–OAR–2013–0495–9666).

impact''). The EPA thus considers such issues as solid waste and wastewater generation as part of determining if a system of emission reduction is ''best'' and ''adequately demonstrated'' under section 111. See Section V.O below (discussion of this rule's potential cross-media impacts).

The further comment that the standard is arbitrary because it fails to impose any requirements on the captured CO_2 is misplaced. The commenter mischaracterizes the standard as requiring capture only. The BSER is not just capturing a certain amount of CO_2, but sequestering it. Sequestration can occur either on-site or off-site. Sequestration sites receiving and injecting the captured CO_2 are required to obtain UIC permits and report under subpart RR of the GHGRP. They must conduct comprehensive monitoring as part of these obligations. Although the NSPS does not impose regulatory requirements on the transportation pipeline or the sequestration site, such requirements already exist under other regulatory programs of the Department of Transportation and the EPA. In particular, the EPA is reasonably relying on the already-adopted, and very rigorous, Class VI well requirements in combination with the subpart RR requirements to provide secure sequestration of captured CO_2. The EPA has also considered carefully the requirements and operating history of the Class II requirements for EOR wells, which, in combination with the subpart RR requirements, ensure protection of USDWs from endangerment, provide the monitoring mechanisms to identify and address potential leakage using SDWA and CAA authorities, and have the practical effect of preventing releases of CO_2 to the atmosphere. This is analogous to the many section 111 standards of performance for metals which result in a captured air pollution control residue to be disposed of pursuant to waste management requirements of the rules implementing the Resource Conservation and Recovery Act. It is also analogous to the many section 111 standards of performance for metals or organics captured in wet air pollution control systems resulting in wastewater discharged to a navigable water where pollutant loadings are controlled under rules implementing the Clean Water Act. Again, these are non-air environmental impacts for which the EPA must account in establishing a section 111(a) standard. The EPA has reasonably done so here based on the regulatory regimes of the Class VI and Class II UIC requirements in combination with the monitoring regime of the subpart RR reporting rules, as well as the CO_2 pipeline standards of the Department of Transportation.

In this regard, the EPA notes that at proposal it acknowledged the possibility ''that there can be downstream losses of CO_2 after capture, for example during transportation, injection or storage.'' 79 FR at 1484. Given the rigorous substantive requirements and the monitoring required by the Class VI rules, the complementary monitoring regime of the subpart RR MRV plan and reporting rules, as well as the regulatory requirements for Class II wells, any such losses would be de minimis. Indeed, the same commenter maintained that the monitoring requirements of the Class VI rule are overly stringent and that a 50-year post-injection site care period is unnecessarily long.[481] As it happens, as noted above, the Class VI rules allow for an alternative post-injection site care period based on a site-specific demonstration. See 40 CFR 146.93(b).

The EPA addresses this comment in more detail in Chapter 2 of the Response-to-Comment Document.

5. Other Perceived Obstacles to Geologic Sequestration

a. Class II to Class VI transition

A number of commenters maintained that the Class VI rules could effectively force all Class II wells to transition to Class VI wells if they inject anthropogenic CO_2, and further maintained that, as a practical matter, this would render EOR unavailable for such CO_2. The EPA disagrees with these comments. Injection of anthropogenic CO_2 into Class II wells does not force transition of these wells to Class VI wells—not during the well's active operation and not when EOR operations cease. We recognize the widespread use of EOR and the expectation that injected CO_2 can remain underground. The EPA issued a memorandum to its regional offices on April 23, 2015 reflecting these principles: [482]

Geologic storage of CO_2 can continue to be permitted under the UIC Class II program.

Use of anthropogenic CO_2 in EOR operations does not necessitate a Class VI permit.

Class VI site closure requirements are not required for Class II CO_2 injection operations.

EOR operations that are focused on oil or gas production will be managed under the Class II program. If oil or gas recovery is no longer a significant aspect of a Class II permitted EOR operation, the key factor in determining the potential need to transition an EOR operation from Class II to Class VI is increased risk to USDWs related to significant storage of CO_2 in the reservoir, where the regulatory tools of the Class II program cannot successfully manage the risk.[483]

b. GHGRP Subpart RR

A number of commenters maintained that no EOR operator would accept captured carbon from an EGU due to the reporting and other regulatory burdens imposed by the monitoring requirements of GHGRP subpart RR.[484] They noted that preparing a subpart RR MRV plan could cost upwards of $100,000 which would be cost prohibitive given other available sources of CO_2.

The EPA disagrees with this comment in several respects. First, the BSER determination and regulatory impact analysis for this rule relies on GS in deep saline formations, not on EOR. However, the EPA also recognizes the potential for sequestering CO_2 via EOR, but disagrees that subpart RR requirements effectively preclude or substantially inhibit the use of EOR.

The cost of compliance with subpart RR is not significant enough to offset the potential revenue for the EOR operator from the sale of produced oil for CCS projects that are reliant on EOR. First, the costs associated with subpart RR are relatively modest, especially in comparison with revenues from an EOR field. In the economic impact analysis for subpart RR, the EPA estimated that an EOR project with a Class II permit would incur a first year cost of up to $147,030 to develop an MRV plan, and an annual cost of $27,787 to maintain the plan; the EPA estimated annual reporting and recordkeeping costs at $13,262 per year.[485] Monitoring costs

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[481] Comments of UARG, p. 63 (Docket entry: EPA–HQ–OAR–2013–0495–9666).

[482] ''Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil Recovery or Gas Recovery Wells to Class VI'', April 23, 2015. Available at: *http://water.epa.gov/type/groundwater/uic/class6/upload/class2eorclass6memo.pdf.*

[483] In this regard, the Class VI rules provide that, owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI geologic sequestration permit when there is an increased risk to USDWs compared to Class II operations. 40 CFR 144.19.

[484] See *e.g.,* comments of UARG, p, 63 (Docket entry: EPA–HQ–OAR–2013–0495–9666); Southern Co., p. 37 (Docket entry: EPA–HQ–OAR–2013–0495–10095); American Petroleum Institute pp. 40–50 Docket entry: EPA–HQ–OAR–2013–0495–10098).

[485] Subpart RR costs are presented in 2008 US dollars.

are estimated to range from $0.02 per metric ton (base case scenario) to approximately $2 per metric ton of CO_2 (high scenario). Using a range of scenarios (that included high end estimates), these subpart RR costs are approximately three to four percent of estimated revenues for an average EOR field, indicating that the costs can readily be absorbed. 75 FR 75073.

Furthermore, there is a demand for new CO_2 by EOR operators, even beyond current natural sources of CO_2. For example, in an April 2014 study, DOE concluded that future development of EOR will need to rely on captured CO_2.[486] Thus, the argument that EOR operators will obtain CO_2 from other sources without triggering subpart RR responsibilities, which assumes adequate supplies of CO_2 from other sources, lacks foundation. In addition, the Internal Revenue Code section 45Q provides a tax credit for CO_2 sequestration which is far greater than subpart RR costs.[487] In sum, the cost of complying with subpart RR requirements, including the cost of MRV, is not significant enough to deter EOR operators from purchasing EGU captured CO_2.

The EPA addresses these comments in more detail in the Response to Comment Document.

c. Conditional exclusion for geologic sequestration of CO2 streams under the Resource Conservation and Recovery Act (RCRA)

Certain commenters voiced concerns that regulatory requirements for hazardous wastes might apply to captured CO_2 and these requirements might be inconsistent with, or otherwise impede, GS of captured CO_2 from EGUs. The EPA has acted to remove any such (highly conjectural) uncertainty. The Resource Conservation and Recovery Act (RCRA) authorizes the EPA to regulate the management of hazardous wastes. In particular, RCRA Subtitle C authorizes a cradle to grave regulatory program for wastes identified as hazardous, whether specifically listed as hazardous or whether the waste fails certain tests of hazardous characteristics. The EPA currently has little information to conclude that CO_2 streams (defined in the RCRA exclusion rule as including incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process) might be identified as ''hazardous wastes'' subject to RCRA Subtitle C regulation.[488] Nevertheless, to reduce potential uncertainty regarding the regulatory status of CO_2 streams under RCRA Subtitle C, and in order to facilitate the deployment of geologic sequestration, the EPA recently concluded a rulemaking to exclude certain CO_2 streams from the RCRA definition of hazardous waste.[489] In that rulemaking, the EPA determined that if any such CO_2 streams would be hazardous wastes, further RCRA regulation is unnecessary to protect human health and the environment provided certain conditions are met. Specifically, the rule conditionally excludes from Subtitle C regulations CO_2 streams if they are (1) transported in compliance with U.S. Department of Transportation or state requirements; (2) injected in compliance with UIC Class VI requirements (summarized above); (3) no other hazardous wastes are mixed with or co-injected with the CO_2 stream; and (4) generators (*e.g.,* emission sources) and Class VI well owners or operators sign certification statements. See 40 CFR 261.4(h)).[490] The D.C. Circuit recently dismissed all challenges to this rule in *Carbon Sequestration Council and Southern Company Services* v. *EPA,* No. 787 F. 3d 1129 (D.C. Cir. 2015).

d. Other perceived uncertainties

Other commenters claimed that various legal uncertainties preclude a finding that geologic sequestration of CO_2 from EGUs can be considered to be adequately demonstrated. Many of the issues referred to in comments relate to property rights: issues of ownership of pore space, relationship of sequestration to ownership of mineral rights, issues of dealing with multiple landowners, lack of state law frameworks, or competing, inconsistent state laws.[491] Other commenters noted the lack of long-term liability insurance, and noted uncertainties regarding long-term liability generally.[492]

An IPCC special report on CCS found that with an appropriate site selection, a monitoring program, a regulatory system, and the appropriate use of remediation methods, the risks of GS would be comparable to risks of current activities, such as EOR, acid gas injection and underground natural gas storage.[493] Furthermore, an interagency CCS task force examined GS-related legal issues thoroughly and concluded that early CCS projects can proceed under the existing legal framework with respect to issues such as property rights and liability.[494] As noted earlier, both the Archer Daniels Midland (ADM) and FutureGen projects addressed siting and operational aspects of GS (including issues relating to volumes of the CO_2 and the nature of the CO_2 injectate) in their permit applications. The fact that these applicants pursued permits indicates that they regarded any potential property rights issues as resolvable.

Commenter American Electric Power (AEP) referred to its own experience with the Mountaineer demonstration project. AEP noted that although this project was not full scale, finding a suitable repository, notwithstanding a generally favorable geologic area, proved difficult. The company referred to years spent in site characterization and digging multiple wells.[495] Other commenters noted more generally that site characterization issues can be time-consuming and difficult, and quoted

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[486] ''Near Term Projections of CO_2 Utilization for Enhanced Oil Recovery''. DOE/NETL–2014/1648. April 2014.

[487] *http://www.irs.gov/irb/2009-44_IRB/ar11.html*. The section 45Q tax credit for calendar year 2015 is $10.92 per metric ton of qualified CO_2 that is captured and used in a qualified EOR project and $21.85 per metric ton of qualified CO_2 that is captured and used in a qualified non-EOR GS project. *http://www.irs.gov/irb/2015-26_IRB/ar14.html*.

[488] No hazardous waste listings apply to CO_2 streams. Therefore, a CO_2 stream could be identified (*i.e.* defined) as a hazardous waste only if it exhibits one or more of the hazardous characteristics. 79 FR 355 (Jan 3. 2014).

[489] 79 FR 350 (Jan. 3, 2014).

[490] The EPA made clear in the final conditional exclusion that that rule does not address, and is not intended to affect the RCRA regulatory status of CO_2 streams that are injected into wells other than Class VI. However, the EPA noted in the preamble to the final rule that (based on the limited information provided in public comments) should CO_2 be used for its intended purpose as it is injected into UIC Class II wells for the purpose of EOR/EGR (enhanced oil recovery/enhanced gas recovery), it is the EPA's expectation that such an injection process would not generally be a waste management activity. 79 FR 355. The EPA encouraged persons to consult with the appropriate regulatory authority to address any fact-specific questions that they may have regarding the status of CO_2 in situations that are beyond the scope of that rule. *Id.* Moreover, use of anthropogenic CO_2 for EOR is long-standing and has flourished in all of the years that EPA's subtitle C regulations (which among other things, define what a solid waste is for purposes of those regulations) have been in place. The RCRA subtitle C regulatory program consequently has not been an impediment to use of anthropogenic CO_2 for EOR.

[491] See *e.g.* Comments of Duke Energy, p. 28 Docket entry: EPA–HQ–OAR–2013–0495–9426); UARG, p. 62 (Docket entry: EPA–HQ–OAR–2013–0495–9666); AEP, p. 91 (Docket entry: EPA–HQ–OAR–2013–0495–10618).

[492] See *e.g.* Comments of UARG, pp. 26 (Docket entry: EPA–HQ–OAR–2013–0495–9666), 62; EEI, p. 92 Docket entry: EPA–HQ–OAR–2013–0495–9780); Duke Energy, pp. 27, 28 Docket entry: EPA–HQ–OAR–2013–0495–9426).

[493] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[494] *http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf*.

[495] AEP Comments at pp. 93, 96 (Docket entry: EPA–HQ–OAR–2013–0495–10618).

studies suggesting that it could take 5 years to obtain a Class VI permit.[496]

The EPA agrees that robust site characterization and selection is important to ensuring capacity needs are met and that the sequestered CO_2 is safely stored. Efforts to characterize geologic formations suitable for GS have been underway at DOE through the RCSPs since 2003 (see Section V.M). Additionally, since 2007, the USGS has been assessing U.S. geologic storage resources for CO_2. As noted earlier, DOE, in partnership with researchers, universities, and organizations across the country, is demonstrating that GS can be achieved safely, permanently, and economically at large scales, and projects supported by the department have safely and permanently stored 10 million metric tons of CO_2.

In the time since the commenter submitted comments several Class VI permits have been issued by the EPA. These projects demonstrate that a GS site permit applicant could potentially prepare and obtain a UIC permit concurrent with permits required for an EGU. With respect to AEP's experience with the Mountaineer demonstration project, notwithstanding difficulties, the company was able to successfully dig wells, and safely inject captured CO_2. Moreover, the company indicated it fully expected to be able to do so at full scale and explained how.[497] The EPA notes further that a monitoring program and its associated infrastructure (*e.g.,* monitoring wells) and costs will be dependent on site-specific characteristics, such as CO_2 injection rate and volume, geology, the presence of artificial penetrations, among other factors. It is thus not appropriate to generalize from AEP's experience, and assume that other sites will require the same number of wells for site characterization or injection. In this regard, we note that the ADM and FutureGen construction permits for Class VI wells involved far fewer injection wells than AEP references.[498] See also discussion of this issue in Section V.I.5 above.

O. Non-air Quality Impacts and Energy Requirements

As part of the determination that SCPC with partial CCS is the best system of emission reduction adequately demonstrated, the EPA has given careful consideration to non-air quality health and environmental impacts and energy requirements, as required by CAA section 111 (a). We have also considered those factors for alternative potential compliance paths to assure that the standard does not have unintended adverse health, environmental or energy-related consequences. The EPA finds that neither the BSER, nor the possible alternative compliance pathways, would have adverse consequences from either a non-air quality impact or energy requirement perspective.

1. Transport and Sequestration of Captured CO_2

As just discussed in detail, the EPA finds that the Class VI and II rules, as complemented by the subpart RR GHGRP reporting and monitoring requirements, amply safeguard against potential of injected CO_2 to degrade underground sources of drinking water and amply protect against any releases of sequestered CO_2 to the atmosphere. The EPA likewise finds that the plenary regulatory controls on CO_2 pipelines assure that CO_2 can be safely conveyed without environmental release, and that these rules, plus the complementary tracking and reporting rules in subpart RR, assure that captured CO_2 will be properly tracked and conveyed to a sequestration site.

2. Water Use Impacts

Commenters claimed that the EPA ignored the negative environmental impacts of the use of CCS for the mitigation of CO_2 emissions from fossil fuel-fired steam generating EGUs. In particular, commenters noted that the use of CCS will increase the water usage at units that implement CCS to meet the proposed standard of performance. At least one commenter claimed that addition of an amine-based CCS system would double the consumptive water use of a power plant, which would be unacceptable, especially in drought-ridden states and in the arid west and referenced a study in the scientific literature as support.[499] The commenter also references a DOE/NETL report that likewise notes significant increases in the amount of cooling and process water required with the use of carbon capture technology.[500] However, those studies discuss increased water use for cases where full CCS (90 percent or greater capture) is implemented. As we discussed in both the proposal and in this preamble, the EPA does not find that highly efficient new generation technology implementing full CCS is the BSER for new steam generating EGUs.

The EPA examined water use predicted from the updated DOE/NETL studies in order to determine the magnitude of increased water usage for a new SCPC implementing partial CCS to meet the final standard of 1,400 lb CO_2/MWh-g. The predicted water consumption for varying levels of partial and full CCS are provided in Table 13. The results show that a new SCPC unit that implements 16 percent partial CCS to meet the final standard would see an increase in water consumption (the difference between the predicted water withdraw and discharge) of about 6.4 percent compared to an SCPC with no CCS and the same net power output. By comparison, a unit implementing 35 percent CCS to meet the proposed emission limitation of 1,100 lb CO_2/MWh-g would see an increase in water consumption of 16.0 percent and a new unit implementing full (90 percent) CCS would see an increase of almost 50 percent.

TABLE 13—PREDICTED WATER CONSUMPTION WITH IMPLEMENTATION OF VARIOUS LEVELS OF PARTIAL CCS [501]

Technology	Raw water consumption, gpm	Increase compared to SCPC, %
SCPC	4,095	—

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[496] See *e.g.* Comments of UARG, p. 55 (Docket entry: EPA–HQ–OAR–2013–0495–9666), citing to Cichanowitz CCS Report (2012).

[497] See AEP FEED Study at pp. 36–43. The company likewise explained the monitoring regime it would utilize to verify containment, and the well construction it would utilize to guarantee secure sequestration. Id. at pp. 44–54. Available at: *www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report*.

[498] The FutureGen UIC Class VI injection well permits (four in total) require nine monitoring wells. *http://www.epa.gov/r5water/uic/futuregen/*. The Archer Daniels Midland UIC Class VI injection well permit issued in September 2014 (CCS2) requires five monitoring wells and the Archer Daniels Midland UIC Class VI injection well permit issued in December 2014 (CCS1) was permitted with two monitoring wells. *http://www.epa.gov/region5/water/uic/adm/*.

[499] See comments of UARG at p. 84 (Docket entry: EPA–HQ–OAR–2013–0495–9666) referencing Haibo Zhai, *et al.,* Water Use at Pulverized Coal Power Plants with Post-combustion Carbon Capture and Storage, 45 *Environ. Sci. Technol.,* 2479–85 (2011).

[500] Id at p. 84 referencing DOE/NETL–402/080108, ''Water Requirements for Existing and Emerging Thermoelectric Plant Technologies'' at 13 (Aug. 2008, Apr. 2009 revision).

Table 13—Predicted Water Consumption With Implementation of Various Levels of Partial CCS[501]—Continued

Technology	Raw water consumption, gpm	Increase compared to SCPC, %
SCPC + 16% CCS	4,359	6.4
SCPC + 35% CCS	4,751	16.0
SCPC + 90% CCS	6,069	48.2
IGCC*	3,334	−18.6
IGCC + 90% CCS*	4,815	17.6

*The IGCC results presented in the DOE/NETL report are for an IGCC with net output of 622 MWe and an IGCC with full CCS with net output of 543 MWe. The water consumption for each was normalized to 550 MWe to be consistent with the SPCP cases.

Similar to other air pollution controls—such as a wet flue gas desulfurization scrubber—utilization of post-combustion amine-based capture systems results in increased consumption of water. However, by finalizing a standard that is less stringent than the proposed limitation and by rejecting full CCS as the BSER, the EPA has reduced the increased amount of water needed as compared to a similar unit without CCS. Further, the EPA notes that there are additional opportunities to minimize the water usage at such a facility. For example, the SaskPower Boundary Dam Unit #3 post-combustion capture project captures water from the coal and from the combustion process and recycles the captured water in the process, resulting in decreased need for withdrawal of fresh water.

The EPA also examined the predicted water usage for a new IGCC and for a new IGCC implementing 90 percent CCS. The predicted water consumption for the new IGCC unit is nearly 20 percent less than that predicted for the new SCPC unit without CCS (and almost 25 percent less than the SCPC unit meeting the final standard). The EPA rejected new IGCC implementing full CCS as BSER because the predicted costs were significantly more than alternative technologies. The EPA also does not find that a new IGCC EGU is part of the final BSER (for reasons discussed in Section V.P). However, the EPA does note that IGCC is a viable alternative compliance option and, as shown here, would result in less water consumption than a compliant SCPC EGU. The EPA also notes that predicted water consumption at a new NGCC unit would be less than half that for a new SCPC EGU with the same net output.[502]

3. Energy Requirements

The EPA also examined the expected impacts on energy requirements for a new unit meeting the final promulgated standard and finds impacts to be minimal. Specifically, the EPA examined the increased auxiliary load or parasitic energy requirements of a system implementing CCS. The EPA examined the predicted auxiliary power demand from the updated DOE/NETL studies in order to determine the increased energy requirement for a new SCPC implementing partial CCS to meet the final standard of 1,400 lb CO_2/MWh-g. The predicted gross power output, the auxiliary power demand, and the parasitic power demand (percent of gross output) are provided in Table 14 for varying levels of partial and full CCS.

Table 14—Predicted Parasitic Power Demand With Implementation of Various Levels of Partial CCS[503]

Generation technology	Gross power output, MWe	Auxiliary power, MWe	Parasitic demand (%)
SCPC	580	30	5.2
SCPC + 16% CCS	599	38	6.3
SCPC + 35% CCS	603	53	8.8
SCPC + 90% CCS	642	91	14.2
IGCC	748	126	16.8
IGCC + 90% CCS	734	191	26.0
CCS	734	191	26.0

The auxiliary power demand is the amount of the gross power output that is utilized within the facility rather than used to produce electricity for sale to the grid. The parasitic power demand (or parasitic load) is the percentage of the gross power output that is needed to meet the auxiliary power demand.[504] In an SCPC EGU without CCS, the auxiliary power is used to primarily to operate fans, motors, pumps, etc. associated with operation of the facility and the associated pollution control equipment. When carbon capture equipment is incorporated, additional power is needed to operate associated equipment, and steam is need to regenerate the capture solvents (*i.e.,* the solvents are heated to release the captured CO_2).

The results in Table 14 show that a new SCPC unit without CCS can expect a parasitic power demand of about 5.2 percent. A new SCPC unit meeting the

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[501] Exhibits A–1 and A–2 at p. 16–17 from ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 22, 2015).

[502] The EPA also finds that the standards would not result in any significant impact on solid waste generation or management. See Section XIII.D below.

[503] Exhibits A–1 and A–2 at p. 16–17 from ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015).

[504] Note that this auxiliary power demand is not necessarily met from power or steam generated from the EGU. External sources can also be utilized for this purpose.

final standard of performance by implementing 16 percent partial CCS will see a parasitic power demand of about 6.3 percent, which is not a significant increase in energy requirement. Of course, new SCPC EGUs that implement higher levels of CCS will expect higher amounts of parasitic power demand. As shown in Table 14, a new SCPC EGU implementing full CCS would expect to utilize over 14 percent of its gross power output to operate the facility and the carbon capture system. But, the EPA does not find that a new SCPC implementing full CCS is the BSER for new fossil-fired steam generating units. See Section V.P.2 below.

The EPA also notes that there is on-going research sponsored by DOE/NETL and others to further reduce the energy requirements of the carbon capture systems. Progress is being made. As was mentioned previously, the heat duty (the energy required to regenerate the capture solvent) for the amine scrubbing process used at the Searles Valley facility in the mid-70's was about 12 MJ/mt CO_2 removed as compared to a heat duty of about 2.5 MJ/mt CO_2 removed for the amine processes used at Boundary Dam and for the amine system that will be used at the WA Parish facility.[505]

The EPA also examined the predicted parasitic power demand for a new IGCC and for a new IGCC implementing 90 percent CCS. As we have noted elsewhere, the auxiliary power demand for a new IGCC unit is more than that for that of a new SCPC. As one can see in Table 14, a new IGCC unit can expect to see a nearly 17 percent parasitic power demand; and a new IGCC unit implementing full CCS would expect a parasitic power demand of nearly 30 percent. Of course, the EPA rejected new IGCC implementing full CCS as BSER because of the potentially unreasonable costs. The EPA also does not find that a new IGCC EGU is part of the final BSER (for reasons discussed elsewhere in Section V.P.1 below). However, as we have noted, the EPA does find IGCC to be a viable alternative compliance option. Utilities and project developers should consider the increased auxiliary power demand for an IGCC when considering their options for new power generation. The EPA also notes that the predicted parasitic load for a new NGCC unit would be about 2 percent—less than half that for a new SCPC EGU with the same net output.[506]

With respect to potential nationwide impacts on energy requirements, as described above in Section V.H.3 and more extensively in the RIA chapter 4, the EPA reasonably projects that no new non-compliant fossil-fuel fired steam electric capacity will be constructed through 2022 (the end of the 8 year review cycle for NSPS). It is possible, as described earlier, that some new sources could be built to preserve fuel diversity, but even so, the number of such sources would be small and therefore would not significantly impact national energy requirements (assuming that such sources would not already be reflected in the baseline conditions just noted).

P. Options That Were Considered by the EPA but Were Ultimately Not Determined To Be the BSER

In light of the comments received, the EPA re-examined several alternative systems of emission reduction and reaffirms in this rulemaking our proposed determination that those alternatives do not represent the "best" system of emission reduction when compared against the other available emission reduction options. These are described below. See also Section IV.B.1 above.

1. Highly Efficient Generation Technology (*e.g.,* Supercritical or Ultra-supercritical Boilers)

In the January 2014 proposal, we considered whether 'Highly Efficient New Generation without CCS Technology' should constitute the BSER for new steam generating units. 79 FR at 1468–69. The discussion focused on the performance of highly efficient generation technology (that does not include any implementation of CCS), such as a supercritical[507] pulverized coal (SCPC) or a supercritical CFB boiler, or a modern, well-performing IGCC unit.

All these options are technically feasible—there are numerous examples of each operating in the U.S. and worldwide. However, we do not find them to qualify as the best system for reduction of CO_2 emissions for the following reasons:

a. Lack of Significant CO_2 Reductions When Compared to Business as Usual

At the outset, we reviewed the emission rates of efficient PC and CFB units. According to the DOE/NETL estimates, a newly constructed subcritical PC unit firing bituminous coal would emit approximately 1,800 lb CO_2/MWh-g,[508] a new highly efficient SCPC unit using bituminous coal would emit nearly 1,720 lb CO_2/MWh-g, and a new IGCC unit would emit about 1,430 lb CO_2/MWh-g.[509] [510] Emissions from comparable sources utilizing sub-bituminous coal or lignite will have somewhat higher CO_2 emissions.[511]

Some commenters noted that new coal-fired plants utilizing supercritical boiler design or IGCC would provide substantial emission reductions compared to the emissions from the existing subcritical coal plants that are currently in wide use in the power sector. However, most of the recent new power sector projects using solid fossil fuel (coal or petroleum coke) as the primary fuel—both those that have been constructed and those that have been proposed—are supercritical boilers and IGCC units. About 60 percent of new coal-fired utility boiler capacity that has come on-line since 2005 was supercritical and of the new capacity that came on-line since 2010, about 70 percent was supercritical. No new coal-fired utility boilers began operation in either 2013 or 2014. Coal-fired power plants that have come on-line most recently include AEP's John W. Turk, Jr. Power Plant, which is a 600 MW ultra-supercritical[512] PC (USCPC) facility located in the southwest corner of Arkansas, and Duke Energy's Edwardsport plant, which is a 618 MW

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[505] "From Lubbock, TX to Thompsons, TX—Amine Scrubbing for Commercial CO_2 Capture from Power Plants", plenary address by Prof. Gary Rochelle at the 12th International Conference on Greenhouse Gas Technology (GHGT–12), Austin, TX (October 2014).

[506] The EPA also finds that the standards would not result in any significant impact on solid waste generation or management. See Section XII.D below.

[507] Subcritical coal-fired boilers are designed and operated with a steam cycle below the critical point of water. Supercritical coal-fired boilers are designed and operated with a steam cycle above the critical point of water. Increasing the steam pressure and temperature increases the amount of energy within the steam, so that more energy can be extracted by the steam turbine, which in turn leads to increased efficiency and lower emissions.

[508] Exhibit ES–2 from "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity", Revision 2, Report DOE/NETL–2010/1397 (November 2010).

[509] "Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants", DOE/NETL–2015/1720 (June 2015); SCPC rates come from Exhibit A–2 and IGCC rates come from Exhibit A–4.

[510] The comparable emissions on a net basis are: subcritical PC—1,890 lb CO_2/MWh-n; SCPC–1,705 lb CO_2/MWh-n; and IGCC—1,724 lb CO_2/MWh-n. (See same references as for gross emissions provided in the text).

[511] Exhibit ES–2 from "Cost and Performance Baseline for Fossil Energy Plants Volume 3b: Low Rank Coal to Electricity: Combustion Cases", Report DOE/NETL–2010/1463 (March 2011).

[512] Ultra-supercritical (U.S.C.) and advanced ultra-supercritical (A–U.S.C.) are terms often used to designate a coal-fired power plant design with steam conditions well above the critical point.

''CCS ready'' [513] IGCC unit located in Knox County, Indiana. Both of those facilities came on-line in 2012. It is likely that the units that initiated operation in 2010 or later were conceived of, planned, designed, and permitted well before 2010—likely in the early 2000s. Thus, it seems clear that the power sector had already, at that point, transitioned to the selection of supercritical boiler technology as ''business as usual'' for new coal-fired power plants. Since that time, there have been other coal-fired power plants that have been proposed and almost all of them have been either supercritical boiler designs or IGCC units. In Table 1 of the Technical Support Document *Fossil Fuel-Fired Boiler and IGCC EGU Projects Under Development: Status and Approach* [514] for the January 2014 proposal, the EPA listed the development status of ''potential transitional sources'' (*i.e.,* projects that had been proposed and had received Prevention of Significant Deterioration (PSD) preconstruction permits as of April 13, 2012). Of the 16 proposed EGU projects in Table 1—most of which have been cancelled or converted to or replaced with NGCC projects—the majority (nine) are either supercritical PC or IGCC designs. Five of the proposed projects were CFB designs with only one being a subcritical PC design.

The EPA is aware of only one new coal-fired power plant that is actively in the construction phase. That plant is Mississippi Power's Kemper County Energy Facility in Kemper County, MS—an IGCC unit that plans to begin operations in 2016 and will implement partial CCS to capture approximately 65 percent of the available CO_2, which will be sold for use in EOR operations.

Considering the direction that the power sector has been taking and the changes that it is undergoing, identifying a new supercritical unit as the BSER and requiring an emission limitation based on the performance of such units thus would provide few, if any, additional CO_2 emission reductions beyond the sector's ''business as usual''. As noted, for the most part, new sources are already designed to achieve at least that emission limitation. This criterion does not itself eliminate supercritical technology from consideration as BSER. However, existing technologies must be considered in the context of the range of technically feasible technologies and, as we discuss elsewhere in this final preamble, partial CCS can achieve emission limitations beyond business as usual and do so at a reasonable cost.

The EPA also considered IGCC technology and whether it represents the BSER for new power plants utilizing coal or other solid fossil fuels. IGCC units, on a gross-output basis, have inherently lower CO_2 emission rates when compared to similarly-sized SCPC units. However, the net emission rates and overall emissions to the atmosphere (*i.e.,* tons of CO_2 per year) tend to be more similar (though still somewhat lower) for new IGCC units when compared to new SCPC units with the same electrical output. Therefore an emission limitation based on the expected performance of a new IGCC unit would result in some CO_2 emission reductions from the segment of the industry that would otherwise construct new PC units, but not from the segment of the industry that would already construct new IGCC units. A gross-output-based emission limitation consistent with the expected performance of a new IGCC unit would still require some additional control, such as partial CCS, on a new supercritical boiler.

As is shown in Section V.J and H, additional emission reductions beyond those that would result from an emission standard based on a new SCPC boiler or even a new IGCC unit as the BSER can be achieved at a reasonable cost. Because practicable emission controls are available that are of reasonable cost at the source level and that will have little cost and energy impact at the national level, the EPA is according significant weight to the factor of amount of emissions reductions in determining the BSER. As discussed above, the D.C. Circuit has emphasized this factor in describing the purpose of CAA section 111 as to achieve ''as much [emission reduction] as practicable.'' [515]

b. Lack of Incentive for Technological Innovation

As discussed above, the EPA is justifying its identification of the BSER based on its weighing of the factors explicitly identified in CAA section 111(a)(1), including the amount of the emission reduction. Under the D.C. Circuit case law, encouraging the development and implementation of advanced control technology must also be considered (and, in any case, may reasonably be considered; see Section V.H.3.d above). Consideration of this factor confirms the EPA's decision not to identify highly efficient generation technology (without CCS) as the BSER. At present, CCS technologies are the most promising options to achieve significant reductions in CO_2 emissions from newly constructed fossil fuel-fired steam generating units. CCS technology is also now a viable retrofit option for some modified, reconstructed and existing sources—depending upon the configuration, location and age of those sources. As CCS technologies are deployed and used more there is an expectation that, based on previous experience with advanced technologies, the performance will improve and the implementation costs will decline. The improved performance and lower costs will provide additional incentive for further implementation in the future.

The Intergovernmental Panel on Climate Change (IPCC) recently released its Fifth Assessment report, [516] which recognizes that widespread deployment of CCS is crucial to reach the long term climate goals. The authors of the report used models to predict the likelihood of stabilizing the atmospheric concentration of CO_2 at 450 ppm by 2050 with or without carbon capture and storage (CCS). They found that several of the models were not able to reach this goal without CCS, which underlines the importance of deploying and further developing CCS on a large scale.

American Electric Power (AEP), in an evaluation of lessons learned from the Phase 1 of its Mountaineer CCS project, wrote: ''AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation.'' [517]

Some commenters felt that the proposed standard of performance for new steam generating units, based on implementation of partial CCS at an emission rate of 1,100 lb/MWh-g, would not serve to promote the increased deployment and implementation of CCS. The commenters argued that such a standard could instead have the unintended result of discouraging the further development of advanced coal generating technologies such as ultra-supercritical boilers and improved IGCC designs.

Commenters further argued that such a standard will stifle further

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[513] A ''CCS ready'' facility is one that is designed such that the CCS equipment can be more easily added at a later time.

[514] Available in the rulemaking docket (entry: EPA–HQ–OAR–2013–0495–0024).

[515] *Sierra Club,* 657 F.2d at 327 & n. 83.

[516] IPCC, Working Group III, Climate Change 2014: Mitigation of Climate Change, *http://mitigation2014.org/report/publication/.*

[517] CCS LESSONS LEARNED REPORT American Electric Power Mountaineer CCS II Project Phase 1, Prepared for The Global CCS Institute Project # PRO 004, January 23, 2012, page 2. See also AEP FEED Study at pp. 4, 63 (same). Available at: *http://www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report.*

development of CCS technologies. Commenters felt that the standard would effectively deter the construction of new coal-fired generation—and, if there is no new coal-fired generation, then there will be no implementation of CCS technology and, therefore, no need for continued research and development of CCS technologies. They argued, in fact, that the best way to promote the development of CCS was to set a standard that did not rely on it.

The EPA does not agree with these arguments and, in particular, does not see how a standard that is not predicated on performance of an advanced control technology would serve to promote development and deployment of that advanced control technology. On the contrary, the history of regulatory actions has shown that emission standards that are based on performance of advanced control equipment lead to increased use of that control equipment, and that the absence of a requirement stifles technology development.

There is a dramatic instance of this paradigm presented in the present record. In 2011, AEP deferred construction of a large-scale CCS retrofit demonstration project on one of its coal-fired power plants because the state's utility regulators would not approve cost recovery for CCS investments without a regulatory requirement to reduce CO_2 emissions. AEP's chairman was explicit on this point, stating in a July 17, 2011 press release announcing the deferral:

> We are placing the project on hold until economic and policy conditions create a viable path forward . . . We are clearly in a classic 'which comes first?' situation. The commercialization of this technology is vital if owners of coal-fueled generation are to comply with potential future climate regulations without prematurely retiring efficient, cost-effective generating capacity. But as a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund the industry's share.[518]

Some commenters also argued that the incremental cost associated with including CCS at the proposed level would prevent new coal-fired units from being built. Instead, they advocated for a standard based on most efficient technology (supercritical) coupled with government subsidies to advance and promote CCS technology. The final standard is less stringent than that proposed, and can be met at a lower cost than the proposed standard, and as explained above in Section V.H, the EPA has carefully evaluated those costs and finds them to be reasonable. Further, the record and current economic conditions (fuel costs, renewables, demand growth, etc.) show that non-economic factors such as a desire for fuel diversity will likely drive future development of any new coal-fired EGUs. For this reason, the EPA does not find the commenters' bare assertions that the incremental cost of CCS (particularly as reasonably modulated for this final standard) would make the difference between constructing and not constructing new coal capacity to be persuasive. Rather, a cost-reasonable standard reflecting use of the new technology is what will drive new technology deployment.

The EPA expects that it is unlikely that a new IGCC unit would install partial CCS to meet the final standard unless the facility is built to take advantage of EOR opportunities or to operate as a poly-generation facility (*i.e.,* to co-produce power along with chemicals or other products). For new IGCC units, the final standard of performance can be met by co-firing a small amount of natural gas. Some commenters argued that IGCC is an advanced technology that, like CCS, should be promoted. The EPA agrees. IGCC is a low-emitting, versatile technology that can be used for purposes beyond just power production (as mentioned just above). Commenters further argued that a requirement to include partial CCS (at a level to meet the proposed standard of performance) would serve to deter—rather than promote—more installation of IGCC technology. We disagree with a similar argument that commenters make with respect to partial CCS for post-combustion facilities, but our final standard moots that argument for IGCC facilities because the final emission limitation of 1,400 lb CO_2/MWh-g will not itself deter installation of IGCC technology, by the terms of the commenters' own argument.

2. ''Full'' Carbon Capture and Storage (*i.e.,* 90 Percent Capture)

We also reconsidered whether the emission limitation for new coal-fired EGUs should be based on the performance of full implementation of CCS technology. For a newly constructed utility boiler, this would mean that a post-combustion capture system would be used to treat the entire flue gas stream to achieve an approximately 90 percent reduction in CO_2 emissions. For a newly constructed IGCC unit, a pre-combustion capture system would be used to capture CO_2 from a fully shifted gasification syngas stream to achieve an approximately 90 percent reduction in CO_2 emissions.

In the proposal for newly constructed sources, we found that ''full CCS'' would certainly result in significant CO_2 reductions from any new source implementing the technology. However, we also found that the costs associated with implementation, on either a new utility boiler system or a new IGCC unit, are predicted to substantially exceed the costs for other dispatchable non-NGCC generating options that are being considered by utilities and project developers (*e.g.,* new nuclear plants and new biomass-fired units). See 79 FR at 1477. This remains the case, and indeed, the difference between cost of full capture and new nuclear technology is estimated to be even greater than at proposal. The EPA thus is not selecting full capture CCS as BSER.

Q. Summary

The EPA finds that the best system of emission reduction adequately demonstrated is a highly efficient supercritical pulverized coal boiler using post-combustion partial CCS so that CO_2 is captured, compressed and safely stored over the long-term. Properly designed, operated, and maintained, this best system can achieve a standard of performance of 1,400 lb CO_2/MWh-g, an emission limitation that is achievable over the 12-operating-month compliance period considering usual operating variability (including use of different coal types, periods of startup and shutdown, and malfunction conditions). This standard of performance is technically feasible, given that the BSER technology is already operating reliably in full-scale commercial application. The technology adds cost to a new facility which the EPA has evaluated and finds to be reasonable because the costs are in the same range as those for new nuclear generating capacity—a competing non-NGCC, dispatchable technology that utilities and project developers are also considering for base load application. The EPA has also considered capital cost increases associated with use of post-combustion partial CCS at the level needed to meet the final standard and found them to be reasonable, and within the range of capital cost increases for this industry in prior NSPS which have been adjudicated as reasonable. The EPA's consideration of costs is also informed by its judgment that new coal-

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[518] *http://www.aep.com/newsroom/newsreleases/?id=1704.*

fired capacity would be constructed not as the most economic option, but for such purposes as preserving fuel diversity in an energy portfolio, and so would not be cost competitive with natural gas-fired capacity, so that some additional cost premium may therefore be reasonable. The EPA has carefully evaluated the non-air quality health and environmental impacts of the final standard and found them to be reasonable: CO_2 pipelines and CO_2 sequestration via deep well injection are subject already to rigorous control under established regulatory programs which assure prevention of environmental release during transport and storage. In addition, water use associated with use of partial CCS at the level to meet the final standard is acceptable, and use of the technology does not impose significant burdens on energy requirements at either the plant or national level. The 1,400 lb CO_2/MWh-g standard reflecting performance of the BSER may be achieved without geographic constraint, both because geologic sequestration and EOR capacity are widely available and accessible, and also because alternative compliance pathways are available in the unusual circumstance where a new coal-fired plant is sited in an area without such access, that area has not already limited construction of new coal-fired capacity in some way, and the area cannot be serviced by coal-by-wire. Accordingly, the EPA finds that the promulgated standard of performance for new fossil fuel-fired steam electric generating units satisfies the requirements of CAA section 111(a).

VI. Rationale for Final Standards for Modified Fossil Fuel-Fired Electric Utility Steam Generating Units

The EPA has determined that, as proposed, the BSER for steam generating units that trigger the modification provisions is each affected unit's own best potential performance as determined by that unit's historical performance. The final standards of performance are similar to those proposed in the June 2014 proposal. Differences between the proposed standards and the final standards issued in this action reflect responses to comments received on the proposal. Those changes are described below.

As noted previously, the EPA is issuing final emission standards only for affected modified steam generating units that conduct modifications resulting in a hourly increase in CO_2 emissions (mass per hour) of more than 10 percent (''large'' modifications). The EPA is continuing to review the appropriate standards for modified sources that conduct modifications resulting in a hourly increase in CO_2 emissions (mass per hour) of less than or equal to 10 percent (''small'' modifications), is not issuing final standards for those sources in this action, and is withdrawing the proposed standards for those sources. See Section XV below.

A. Rationale for Final Applicability Criteria for Modified Steam Generating Units

Final applicability criteria for modified steam generating EGUs include those discussed earlier in Section III.A.1 (General Applicability) and Section III.A.3 (Applicability Specific to Modified Sources).

CAA section 111(a)(4) defines a ''modification'' as ''any physical change in, or change in the method of operation of, a stationary source'' that either ''increases the amount of any air pollutant emitted by such source or . . . results in the emission of any air pollutant not previously emitted.'' Certain types of physical or operational changes are exempt from consideration as a modification. Those are described in 40 CFR 60.2, 60.14(e). To be clear, our action in this final rule, and the discussion below, does not change anything concerning what constitutes or does not constitute a modification under the CAA or the EPA's regulations.[519]

A modified steam generating unit is a source that fits the definition and applicability criteria of a fossil fuel-fired steam generating unit and that commences a qualifying modification on or after June 18, 2014 (the publication date of the proposed modification standards). 79 FR 34960.

For the reasons discussed below, the EPA in this final action is finalizing requirements only for steam generating units that conduct modifications resulting in an increase in hourly CO_2 emissions (mass per hour) of more than 10 percent as compared to the source's highest hourly emission during the previous five years. With respect to modifications with smaller increases in CO_2 emissions (specifically, steam generating units that conduct modifications resulting in an increase in hourly CO_2 emissions (mass per hour) of 10 percent or less compared to the source's highest hourly emission during the previous 5 years), the EPA is not finalizing any standard or other requirements, and is withdrawing the June 2014 proposal with respect to these sources (see Section XV below).

The effect of the EPA's deferral on setting standards for sources undertaking modifications resulting in smaller increases in CO_2 emissions and the withdrawal of the June 2014 proposal with respect to such sources is that such sources will continue to be existing sources and subject to requirements under section 111(d). This is because an existing source does not always become a new source when it modifies. Under the definition of ''new source'' in section 111(a)(2), an existing source only becomes a new source if it modifies after the publication of proposed or final regulations that will be applicable to it. Thus, if an existing source modifies at a time that there is no promulgated final standard or pending proposed standard that will be applicable to it as a modified ''new'' source, that source is not a new source and continues to be an existing source. Here, because the EPA is not finalizing standards for sources undertaking modifications resulting in smaller increases in CO_2 emissions and is withdrawing the proposal with respect to such sources, these sources do not fall within the definition of ''new source'' in section 111(a)(2) and continue to be an ''existing source'' as defined in section 111(a)(6). See Section XV below.

As we discussed in the June 2014 proposal, the EPA has historically been notified of only a limited number of NSPS modifications[520] involving fossil steam generating units and therefore predicted that very few of these units would trigger the modification provisions and be subject to the proposed standards. Given the limited information that we have about past modifications, the agency has concluded that it lacks sufficient information to establish standards of performance for all types of modifications at steam generating units at this time. Instead, the EPA has determined that it is appropriate to establish standards of performance at this time for larger modifications, such as major facility upgrades involving, for example, the refurbishing or replacement of steam turbines and other equipment upgrades that result in substantial increases in a unit's hourly CO_2 emissions rate. The agency has determined, based on its review of public comments and other publicly available information, that it has adequate information regarding the types of modifications that could result in large increases in hourly CO_2 emissions, as well as on the types of

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[519] CAA section 111(a)(4); See also 40 CFR 60.14 concerning what constitutes a modification, how to determine the emission rate, how to determine an emission increase, and specific actions that are not, by themselves, considered modifications.

[520] NSPS modifications resulting in increases in hourly emissions of criteria pollutants.

measures available to control emissions from sources that undergo such modifications, and on the costs and effectiveness of such control measures, upon which to establish standards of performance for modifications with large emissions increases at this time.

In establishing standards of performance at this time for modifications with large emissions increases, but not for those with small increases, the EPA is exercising its policy discretion to promulgate regulatory requirements in a sequential fashion for classes of modifications within a source category, accounting for the information available to the agency, while also focusing initially on those modifications with the greatest potential environmental impact. This approach is consistent with the case law that authorizes agencies to establish a regulatory framework in an incremental fashion, that is, a step at a time.[521]

To be clear, the EPA is not reaching a final decision as to whether it will regulate modifications with smaller increases, or even that such modifications should be subject to different requirements than we are finalizing in this rule for the modifications with larger increases. We have made no decisions and this matter is not concluded. We plan to continue to gather information, consider the options for modifications with smaller increases, and, in the future, develop a proposal for these modifications or otherwise take appropriate steps.

As a means of determining the proper threshold between the larger and smaller increases in CO_2 emissions, the EPA examined changes in CO_2 emissions that may result from large, capital-intensive projects, such as major facility upgrades involving the refurbishing or replacement of steam turbines and other equipment upgrades that would significantly increase a unit's capacity to burn more fossil fuel, thereby resulting in large emissions increases. Major upgrades such as these could increase a steam generating unit's hourly CO_2 emissions by well over 10 percent.[522]

An example of such major upgrade would be work performed at AmerenUE's Labadie Plant, a facility with four 600–MW (nominal) coal-fired units located 35 miles west of St. Louis. In the early 2000s, plant staff conducted process improvements that raised maximum unit capacity by nearly 10 percent (from 580 MW to 630 MW).[523] Those changes included boiler improvements necessitated by its switch from bituminous to subbituminous coal,[524] installation of low-NO_X burners, an overfire air system, and advanced computer controls. One of the performance gains came from upgrading all four steam turbines, which AmerenUE chose to replace as modules allowing engineers more freedom to maximize performance unconstrained by the units' existing outer casing.

Another example is the refurbishment of the 2,100 MW Eskom Arnot coal-fired power plant in South Africa with a resulting increase in its power output by 300 MW to 2,400 MW—an increase in capacity of 14 percent.[525] For each of the plant's six steam generating units, the company conducted a complete retrofit of the high pressure and intermediate pressure steam turbines, a capacity upgrade of the low pressure steam turbine, and the replacement and upgrade of associated turbine side pumps and auxiliaries. In addition, major upgrades to the boiler plant were conducted, including supply of new pressure part components, new burners, and modification to other equipment such as the coal mills and classifiers, fans, and heaters. Other examples are provided in a technical memo available in the rulemaking docket.[526]

The EPA does not intend to imply that these specific projects would have resulted in an increase in hourly CO_2 emissions of greater than 10 percent. Capacity increases are often the result of efficient improvements or are accompanied by other facility improvements that can offset emissions increases due to increased fuel input capacity. However, these examples are intended to show the types of large, more capital intensive projects that can potentially result in increases in hourly emissions of CO_2 of at least 10 percent.

The EPA believes that it is reasonable to set the threshold between "large" modifications and "small" modifications at 10 percent, a level commensurate with the magnitude of the emissions increases that could result from the types of projects described above, and we are issuing a final standard of performance for those sources that conduct modifications resulting in hourly CO_2 emission increases that exceed that threshold. We are not issuing standards of performance for those sources that conduct modifications resulting in an hourly increase of CO_2 emissions of less than or equal to 10 percent.

Therefore, the EPA is withdrawing the proposed standards for those sources that conduct modifications resulting in a hourly increase in CO_2 emissions (mass per hour) of less than or equal to ten percent and is not issuing final standards for those sources at this time. See Section XV below. Utilities, states and others should be aware that the differentiation between modifications with larger and smaller increases in CO_2 emissions only applies to sources covered under 40 CFR part 60, subpart TTTT, *i.e.,* it is only applicable to CO_2 emissions from fossil fuel-fired steam generating units. There is no similar provision for criteria pollutants or for other source categories. Utilities, states and others should also be aware that the distinction between large and small modifications only applies to NSPS modifications. Sources undertaking modifications may still be subject to requirements of New Source Review under CAA Title I part C or D (which have different standards for modifications than the NSPS and require a case-by-case analysis) or other CAA requirements.

The EPA notes that some commenters expressed concern that a number of existing fossil steam generating units, in order to fulfill requirements of an approved CAA section 111(d) plan, may pursue actions that involve physical or operational changes that result in some increase in their CO_2 emissions on an hourly basis, and thus constitute

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[521] As the U.S. Supreme Court recently stated in *Massachusetts* v. *EPA,* 549 U.S. 497, 524 (2007): " 'Agencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop;' " and instead they may permissibly implement such regulatory programs over time, " 'refining their preferred approach as circumstances change and as they develop a more nuanced understanding of how best to proceed.' " *See Grand Canyon Air Tour Coalition* v. *F.A.A.,* 154 F.3d 455 (D.C. Cir. 1998), *City of Las Vegas* v. *Lujan,* 891 F.2d 927, 935 (D.C. Cir. 1989), *National Association of Broadcasters* v. *FCC,* 740 F.2d 1190, 1209–14 (D.C. Cir. 1984). See also, *Hazardous Waste Treatment Council* v. *U.S. E.P.A.,* 861 F.2d 277, 287 (D.C. Cir. 1988) ("[A]n agency's failure to regulate more comprehensively is not ordinarily a basis for concluding that the regulations already promulgated are invalid. 'The agency might properly take one step at a time.' *United States Brewers Assoc.* v. *EPA,* 600 F.2d 974,982 (D.C. Cir. 1979). Unless the agency's first step takes it down a path that forecloses more comprehensive regulation, the first step is not assailable merely because the agency failed to take a second. The steps may be too plodding, but that raises an entirely different issue . . . .").

[522] See *e.g.,* Power Engineering, Steam Turbine Upgrades Boost Plant Reliability, Efficiency, available at *www.power-eng.com/articles/print/volume-116/issue-11/features/steam-turbine-upgrades-boost-plant-reliability-efficiency.html.*

[523] "Steam turbine upgrading: Low-hanging fruit", Power (04/15/2006), *www.powermag.com/steam-turbine-upgrading-low-hanging-fruit.*

[524] Note that a change in coal-type or change in the use of other raw material does not necessarily constitute an "operational change". See 40 CFR 60.14(e)(4).

[525] *www.alstom.com/press-centre/2006/10/alstom-signs-power-plant-upgrade-and-retrofit-contract-with-eskom-in-south-africa/.*

[526] See "U.S. DOE Information Relevant to Technical Basis for "Large Modification" Threshold" available in the rulemaking docket EPA–HQ–OAR–2013–0495.

modifications. Some commenters suggested that the EPA should exempt projects undertaken specifically for the purpose of complying with CAA section 111(d).

The EPA does not have sufficient information at this time to predict the full array of actions that existing steam generating units may undertake in response to applicable requirements under an approved CAA section 111(d) plan, or which, if any, of these actions may result in increases in CO_2 hourly emissions. Nevertheless, the EPA expects that, to the extent actions undertaken by existing steam generating units in response to 111(d) requirements trigger modifications, the magnitude of the increases in hourly CO_2 emissions associated with such modifications would generally be smaller and would therefore generally not subject such modifications to the standards of performance that the EPA is finalizing in this rule for modified steam generating units with larger increases in hourly CO_2 emissions.

B. Identification of the Best System of Emission Reduction

The EPA has determined that, as was proposed, the BSER for steam generating units that trigger the modification provisions is the affected EGU's own best potential performance as determined by that source's historical performance.

The EPA proposed that the BSER for modified steam generating EGUs is each unit's own best potential performance based on a combination of best operating practices and equipment upgrades. Specifically, the EPA co-proposed two alternative standards for modified utility steam generating units. In the first co-proposed alternative, modified steam generating EGUs would be subject to a single emission standard determined by the affected EGU's best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional 2 percent emission reduction. The EPA proposed that the standard could be met through a combination of best operating practices and equipment upgrades. To account for facilities that have already implemented best practices and equipment upgrades, the proposal also specified that modified facilities would not have to meet an emission standard more stringent than the corresponding standard for reconstructed EGUs.

The EPA also co-proposed that the specific standard for modified sources would be dependent on the timing of the modification. We proposed that sources that modify prior to becoming subject to a CAA section 111(d) plan would be required to meet the same standard described in the first co-proposal—that is, the modified source would be required to meet a unit-specific emission limit determined by the affected EGU's best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional 2 percent emission reduction (based on equipment upgrades). We also proposed that sources that modify after becoming subject to a CAA section 111(d) plan would be required to meet a unit-specific emission limit that would be determined by the CAA section 111(d) implementing authority and would be based on the source's expected performance after implementation of identified unit-specific energy efficiency improvement opportunities.

The final standards in this action do not depend upon when the modification commences (as long as it commences after June 8, 2014). The EPA received comments on the June 2014 proposal that called into question the need to differentiate the standard based on when the modification was undertaken. Further, commenters noted that the proposed requirements for sources modifying after becoming subject to a CAA section 111(d) plan, which were based on energy efficiency improvement opportunities were vague and that standard setting under CAA section 111(b) is a federal duty and would require notice-and-comment rulemaking. The EPA considered those comments and has determined that we agree that there is no need for subcategories based on the timing of the modification.

C. BSER Criteria

1. Technical Feasibility

The EPA based technical feasibility of the unit-specific efficiency improvement on analyses done to support heat rate improvement for the proposed CAA section 111(d) emission guidelines (Clean Power Plan). That work was summarized in Chapter 2 of the TSD, ''GHG Abatement Measures''.[527] In response to comments on the proposed Clean Power Plan, the approach was adjusted, as described in the final CAA section 111(d) emission guidelines. As with proposed actions, the EPA is basing technical feasibility for final standards for modified source efficiency improvements on the analyses for heat rate improvements for the CAA 111(d) final rule.

2. Cost

Any efficiency improvement made by EGUs for the purpose of reducing CO_2 emissions will also reduce the amount of fuel that EGUs consume to produce the same electricity output. The cost attributable to CO_2 emission reductions, therefore, is the net cost of achieving heat rate improvements after any savings from reduced fuel expenses. As summarized below, we estimate that, on average, the savings in fuel cost associated with a 4 percent heat rate improvement would be sufficient to cover much of the associated costs, and thus that the net costs of heat rate improvements associated with reducing CO_2 emissions from affected EGUs are relatively low.

We recognize that our cost analysis just described will represent the costs for some EGUs better than others because of differences in EGUs' individual circumstances. We further recognize that reduced generation from coal-fired EGUs will tend to reduce the fuel savings associated with heat rate improvements, thereby raising the effective cost of achieving the CO_2 emission reductions from the heat rate improvements. Nevertheless, we still expect that the majority of the investment required to capture the technical potential for CO_2 emission reductions from heat rate improvements would be offset by fuel savings, and that the net costs of implementing heat rate improvements as an approach to reducing CO_2 emissions from modified fossil fuel-fired EGUs are reasonable. The EPA further notes that the types of large, more capital intensive projects that may trigger the ''larger modifications'' threshold (*i.e.,* result in an hourly increase in CO_2 emissions of more than 10 percent) often are undertaken in order to increase the capacity of the source but also to improve the heat rate or efficiency of the unit.

3. Emission Reductions

This approach would achieve reasonable reductions in CO_2 emissions from the affected modified units as those units will be required to meet an emission standard that is consistent with more efficient operation. In light of the limited opportunities for emission reductions from retrofits, these reductions are adequate.

4. Promotion of Technology and Other Systems of Emission Reduction

As noted previously, the case law makes clear that the EPA is to consider

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[527] Technical Support Documents ''GHG Abatement Measures'' (proposal) and ''GHG Mitigation Measures'' (final) available in the rulemaking docket EPA–HQ–OAR–2013–0495.

the effect of its selection of the BSER on technological innovation or development, but that the EPA also has the authority to weigh this factor, along with the various other factors. With the selection of emissions controls, modified sources face inherent constraints that newly constructed greenfield and even reconstructed sources do not; as a result, modified sources present different, and in some ways more limited, opportunities for technological innovation or development. In this case, the standards promote technological development by promoting further development and market penetration of equipment upgrades and process changes that improve plant efficiency.

VII. Rationale for Final Standards for Reconstructed Fossil Fuel-Fired Electric Utility Steam Generating Units

A. Rationale for Final Applicability Criteria for Reconstructed Sources

The applicability rationale for reconstructed utility steam generating units is the same as for newly constructed utility steam generating units. We are finalizing the same general criteria and not amending the reconstruction provisions included in the general provisions.

B. Identification of the Best System of Emission Reduction

In the proposal, the EPA evaluated seven different control technology configurations to determine the BSER for reconstructed fossil fuel-fired boiler and IGCC EGUs: (1) The use of partial CCS, (2) conversion to (or co-firing with) natural gas, (3) the use of CHP, (4) hybrid power plants, (5) reductions in generation associated with dispatch changes, renewable generation, and demand side energy efficiency, (6) efficiency improvements achieved through the use of the most efficient generation technology, and (7) efficiency improvements achieved through a combination of best operating practices and equipment upgrades.

Although the EPA concluded that the first 4 technologies met most of the evaluation criteria, namely they are adequately demonstrated, have reasonable costs and provide GHG emissions reductions, they were inappropriate for BSER due to site specific constraints for existing EGUs on a nationwide basis. We rejected best operating practices and equipment upgrades because we concluded the GHG reductions are not sufficient to qualify as BSER. The majority of commenters agree with the EPA's decision that these technologies are not BSER. In contrast, as described in more detail later in this section a few commenters did support partial CCS as BSER.

The fifth option, reductions in generation associated with dispatch changes, renewable generation, and demand side energy efficiency, is comparable to application of measures identified in building blocks two, three and four in the emissions guidelines that we proposed under CAA section 111(d). We solicited comment on any additional considerations that the EPA should take into account in the applicability of building blocks two, three and four in the BSER determination. Most commenters stated that building blocks two, three and four should not be considered for reconstructed sources.

The proposed BSER was based on the performance of the most efficient generation technology available, which we concluded was the use of the best available subcritical steam conditions for small units and the use of supercritical steam conditions for large units. We concluded this technology to be technically feasible, to have sufficient emission reductions, to have reasonable costs, and some opportunity for technological innovation. The proposed emission standard for these sources was 1,900 lb CO_2/MWh-n for units with a heat input rating of greater than 2,000 MMBtu/h and 2,100 lb CO_2/MWh-n for units with a heat input rating of 2,000 MMBtu/h or less. The difference in the proposed standards for larger and smaller units was based on greater availability of higher pressure/temperature steam turbines (*e.g.* supercritical steam turbines) for larger units. As explained in Section III of this preamble, we are finalizing the standard on a gross output basis for utility steam generating units. The equivalent gross-output-based standards are 1,800 lb CO_2/MWh and 2,000 lb CO_2/MWh respectively.

We solicited comment on multiple aspects of the proposed standards. First, we solicited comment on a range of 1,600 to 2,000 lb CO_2/MWh-g for large units and 1,800 to 2,200 lb CO_2/MWh-g for small units. We also solicited comment on whether the standards for utility boilers and IGCC units should be subcategorized by primary fuel type. In addition, we solicited comment on if there are sufficient alternate compliance technologies (*e.g.,* co-firing natural gas) that the small unit subcategory is unnecessary and should be eliminated. Those small sources would be required to meet the same emission standard as large utility boilers and IGCC units.

Many commenters supported the upper limits of the suggested ranges, saying the standard will be consistently met. Some commenters raised concerns about the achievability of these limits for the many boiler and fuel types. A few commenters suggested that there should be separate subcategories for coal-fired utility boilers and IGCC units, since IGCC units have demonstrated limits closer to 1,500 lb CO_2/MWh-n and the units' designs are so fundamentally different. Some commenters said that CFB (due to lower maximum steam temperatures), IGCC, and traditional boilers each need their own subcategory. Some commenters suggested that due to high moisture content and high relative CO_2 emissions of lignite, lignite-fired units should have its own subcategory. Other commenters opposed the proposed standards for reconstructed units because they thought the BSER determination for reconstructed subpart Da units was inconsistent with the BSER determination for newly constructed units. These commenters stated that the EPA did not provide sufficient justification for eliminating partial carbon capture and sequestration (CCS). These commenters also stated that the reason the EPA gave for dismissing CCS in the proposal was a lack of ''sufficient information about costs.'' These commenters hold that the cost rationale does not apply for reconstructed coal-fired power plants. The fact that reconstructed units may face greater costs to comply with a CAA section 111(b) standard than new sources does not relieve them of their compliance obligation.

Based on a review of the comments, we have concluded that both the proposed BSER and emission standards are appropriate, and we are finalizing the standards as proposed. Nothing in the comments changed our view that the BSER for reconstructed steam generating units should be based on the performance of a well operated and maintained EGU using the most efficient generation technology available, which we have concluded is a supercritical pulverized coal (SCPC) or supercritical circulating fluidized bed (CFB) boiler for large units, and subcritical for small units. As described at proposal, we have concluded that these standards are achievable by all the primary coal types. The final standards for reconstructed utility boilers and IGCC units is 1,800 lb CO_2/MWh-g for sources with a heat input rating of greater than 2,000 MMBtu/h and 2,000 lb CO_2/MWh-g for sources with a heat input rating of 2,000 MMBtu/h or less.

While the final emission standards are based on the identified BSER, a reconstructed EGU would not necessarily have to rebuild the boiler to use steam temperatures and pressures that are higher than the original design. As commenters noted, a reconstructed unit is not required to meet the standards if doing so is deemed to be ''technologically and economically'' infeasible. 40 CFR 60.15(b). This provision inherently requires case-by-case reconstruction determinations in the light of considerations of economic and technological feasibility. However, this case-by-case determination would consider the identified BSER (the use of the best available steam conditions), as well as—at a minimum—the first four technologies the EPA considered, but rejected, as BSER for a nationwide rule. One or more of these technologies could be technically feasible and reasonable cost, depending on site specific considerations and, if so, would likely result in sufficient GHG reductions to comply with the applicable reconstructed standards. Finally, in some cases, equipment upgrades and best operating practices would result in sufficient reductions to achieve the reconstructed standards.

VIII. Summary of Final Standards for Newly Constructed and Reconstructed Stationary Combustion Turbines

This section summarizes the final applicability requirements, BSER determinations, and emission standards for newly constructed and reconstructed stationary combustion turbines. In addition, it also summarizes significant differences between the proposed and final provisions.

A. Applicability Requirements

We are finalizing BSER determinations and emission standards for newly constructed and reconstructed stationary combustion turbines that (1) have a base load rating for fossil fuels greater than 260 GJ/h (250 MMBtu/h) and (2) serve a generator capable of selling more than 25 MW-net of electricity to the grid. We also are finalizing applicability requirements that will exempt from the final standards (1) all stationary combustion turbines that are dedicated non-fossil fuel-fired units (*i.e.,* combustion turbines capable of combusting 50 percent or more non-fossil fuel) and subject to a federally enforceable permit condition restricting annual fossil fuel use to 10 percent or less of a unit's annual heat input capacity; (2) the large majority of industrial CHP units (*i.e.,* CHP combustion turbines that are subject to a federally enforceable permit condition limiting annual net-electric sales to the product of the unit's net design efficiency multiplied by the unit's potential output, or 219,000 MWh, whichever is greater); (3) combustion turbines that are physically incapable of burning natural gas (*i.e.,* not connected to a natural gas pipeline); and (4) municipal waste combustors and commercial or industrial solid waste incinerators (units subject to subparts Eb or CCCC of this part).

For combustion turbines subject to an emission standard, we are finalizing three subcategories: base load natural gas-fired units, non-base load natural gas-fired units, and multi-fuel-fired units. We use the term base load natural gas-fired units to refer to stationary combustion turbines that (1) burn over 90 percent natural gas and (2) sell electricity in excess of their design efficiency (not to exceed 50 percent) multiplied by their potential electric output. To be in this subcategory, a stationary combustion turbine must exceed the ''natural gas-use criterion'' on a 12-operating-month rolling average and the ''percentage electric sales'' criterion on both a 12-operating-month and 3-year rolling average basis. We use the term non-base load natural gas-fired units to refer to stationary combustion turbines that (1) burn over 90 percent natural gas and (2) have net-electric sales equal to or below their design efficiency (not to exceed 50 percent) multiplied by their potential electric output. These criteria are calculated on the same rolling average bases as for the base load subcategory. Finally, we use the term multi-fuel-fired units to refer to stationary combustion turbines that burn 10 percent or more non-natural gas on a 12-operating-month rolling average basis. We are not finalizing the proposed emission standards for modified sources and are withdrawing those standards. We explain our rationale for these final decisions in Sections IX and XV of this preamble.

B. Best System of Emission Reduction

We are finalizing BSER determinations for the three subcategories of stationary combustion turbines referred to above: base load natural gas-fired units, non-base load natural gas-fired units, and multi-fuel-fired units. For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, the BSER is the use of efficient NGCC technology. For newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines, the BSER is the use of clean fuels (*i.e.,* natural gas with an allowance for a small amount of distillate oil). For multi-fuel-fired stationary combustion turbines, the BSER is also the use of clean fuels (*e.g.,* natural gas, ethylene, propane, naphtha, jet fuel kerosene, fuel oils No. 1 and 2, biodiesel, and landfill gas).

C. Final Emission Standards

For all newly constructed and reconstructed base load natural gas-fired combustion turbines, we are finalizing an emission standard of 1,000 lb CO_2/MWh-g, calculated on a 12-operating-month rolling average basis. We are also finalizing an optional emission standard of 1,030 lb CO_2/MWh-n, calculated on a 12-operating-month rolling average basis, for stationary combustion turbines in this subcategory. For newly constructed and reconstructed non-base load natural gas-fired combustion turbines, we are finalizing a standard of 120 lb CO_2/MMBtu, calculated on a 12-operating-month rolling average basis. For newly constructed and reconstructed multi-fuel-fired combustion turbines, we are finalizing a standard of 120 to 160 lb CO_2/MMBtu, calculated on a 12-operating-month rolling average basis. The emission standard for multi-fuel-fired combustion turbines co-firing natural gas with other fuels shall be determined at the end of each operating month based on the percentage of co-fired natural gas. Table 15 summarizes the subcategories, BSER determinations, and emission standards for combustion turbines.

TABLE 15—COMBUSTION TURBINE SUBCATEGORIES AND BSER

Subcategory	BSER	Emission standard
Base load natural gas-fired combusiton turbines	Efficient NGCC	1,000 lb CO_2/MWh-g or 1,030 lb CO_2/MWh-n
Non-base load natural gas-fired combustion turbines	Clean fuels	120 lb CO_2/MMBtu
Multi-fuel-fired combustion turbines	Clean fuels	120 to 160 lb CO_2/MMBtu [528]

D. Significant Differences Between Proposed and Final Combustion Turbine Provisions

As shown in Tables 16 and 17 below, the proposed rule included several general applicability criteria and two subcategorization criteria for combustion turbines. In addition to the proposed applicability and subcategorization framework, we solicited comment on a ‘‘broad applicability approach’’ that included most combustion turbines irrespective of the actual amount of electricity sold to the grid or the actual amount of natural gas burned (*i.e.,* non-base load units and multi-fuel-fired units, respectively). The broad applicability approach changed the proposed ‘‘percentage electric sales’’ and ‘‘natural gas-use’’ criteria to distinguish among subcategory-specific emissions standards. Specifically, in the broad applicability approach, we solicited comment on subjecting non-base load units and multi-fuel-fired units to ‘‘no emissions standard,’’ while still including them in the general applicability. We also solicited comment on establishing a separate numerical standard for non-base load units. The final rule retains all of the proposed applicability criteria in some form, but most closely tracks the broad applicability approach by finalizing the percentage electric sales and natural gas-use criteria as thresholds that distinguish among three subcategories of combustion turbines with separate emissions standards.

The final rule also includes exceptions to the broad applicability approach that we solicited comment on, with some changes that are responsive to public comments. Categorical exceptions to the broad applicability criteria are the exclusions for CHP units, non-fossil fuel units, and combustion turbines not able to combust natural gas. First, the proposed applicability criteria did not include CHP units that were constructed for the purpose of or that actually sell one-third or less of their potential electric output or 219,000 MWh, whichever is greater, to the grid. The final rule eliminates the ‘‘constructed for the purpose of’’ and actual sales aspects of the proposal and replaces them with an exemption for CHP units that take federally enforceable permit conditions restricting net-electric sales to a percentage of potential electric sales based on the unit’s design efficiency or 219,000 MWh, whichever is greater. Second, the proposed applicability criteria did not include non-fossil fuel units that burn 10 percent or less fossil fuel on a 3-year rolling average. The final rule similarly replaces the actual fuel-use aspect of the proposal with an exemption for non-fossil fuel units that take federally enforceable permit conditions limiting fossil-fuel use to 10 percent or less of annual heat input capacity. Finally, the proposed applicability criteria did not include combustion turbines that burn 90 percent or less natural gas on a 3-year rolling average basis. In contrast, the final rule includes most fossil fuel-fired combustion turbines regardless of the amount of natural gas burned, with an exception for combustion turbines that are not connected to natural gas pipelines. Finally, in response to public comments, we are not finalizing the subcategories for large and small combustion turbines that were contained in the proposal. Instead, all base load natural gas-fired combustion turbines must meet an emission standard of 1,000 lb CO_2/MWh-g.

TABLE 16—PROPOSED APPLICABILITY CRITERIA VERSUS FINAL APPLICABILITY CRITERIA

Applicability Criteria	Proposed Applicability	Final Applicability
Base load rating criterion	Base load rating > 73 MW (250 MMBtu/h)	Base load rating > 260 GJ/h [529] (250 MMBtu/h)
Total electric sales criterion	Constructed for purpose of and actually selling > 219,000 MWh-n to the grid.	Ability to sell > 25 MW-n to the grid
Percentage electric sales criterion	Constructed for purpose of and having actual net-sales to the grid > one-third of potential electric output.	Changed to subcategorization criterion per broad applicability approach
Natural gas-use criterion	Actually burns > 90 percent natural gas	• Changed to subcategorization criterion per broad applicability approach • Exemption for combustion turbines that are not connected to a natural gas supply
Fossil fuel-use criterion	Actually burns > 10 percent fossil fuel	Exemption based on permit condition limiting amount of fossil fuel burned to ≤ 10 percent of annual heat input capacity
Combined Heat and Power (CHP) exemption	NA	Exemption based on permit condition limiting net-electric sales to $\leq$ design efficiency multiplied by potential electric output, or 219,000 MWh-n, whichever is greater
Non-EGU exemption	Exemption for municipal solid waste combustors and commercial or industrial solid waste incinerators.	Same as proposal

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[528] The emission standard for combustion turbines co-firing natural gas with other fuels shall be determined based on the amount of co-fired natural gas at the end of each operating month.

TABLE 17—PROPOSED SUBCATEGORIES VERSUS FINAL SUBCATEGORIES

Subcategory	Proposed Criteria	Final Criteria
Small combustion turbine subcategory	Base load rating ≤ 850 MMBtu/h	NA
Large combustion turbine subcategory	Base load rating > 850 MMBtu/h	NA
Base load natural gas-fired base load combustion turbine subcategory.	NA	• Actually burns > 90 percent natural gas • Net-electric sales > design efficiency (not to exceed 50 percent) multiplied by potential electric output
Non-base load natural gas-fired combustion turbine subcategory.	NA	• Actually burns > 90 percent natural gas • Net-electric sales ≤ design efficiency (not to exceed 50 percent) multiplied by potential electric output
Multi-fuel-fired combustion turbine subcategory	NA	Actually burns ≤ 90 percent natural gas

IX. Rationale for Final Standards for Newly Constructed and Reconstructed Stationary Combustion Turbines

This section discusses the EPA's rationale for the final applicability criteria, BSER determinations, and standards of performance for newly constructed and reconstructed stationary combustion turbines. In this section, we present a summary of what we proposed, a selection of the significant comments we received, and our rationale for the final determinations, including how the comments influenced our decision-making.

A. Applicability

This section describes the proposed applicability criteria, applicability issues we specifically solicited comment on, the relevant significant comments, and the final applicability criteria. We also provide our rationale for finalizing applicability criteria based strictly on design and permit restrictions rather than actual operating characteristics. Finally, we explain why the proposed percentage electric sales and natural gas-use applicability criteria are being finalized instead as criteria to distinguish between separate subcategories of stationary combustion turbines.

1. Proposed Applicability Criteria

In the January 2014 proposal, we proposed several applicability criteria for stationary combustion turbines. Specifically, to be subject to the proposed emission standards, we proposed that a unit must (1) be capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel; (2) be constructed for the purpose of supplying and actually supply more than one-third of its potential electric output capacity to a utility power distribution system for sale (that is, to the grid) on a 3-year rolling average; (3) be constructed for the purpose of supplying and actually supply more than 219,000 MWh net-electric output to the grid on a 3-year rolling average; (4) combust over 10 percent fossil fuel on a 3-year rolling average; and (5) combust over 90 percent natural gas on a 3-year rolling average. We proposed exempting municipal solid waste combustors and commercial and industrial solid waste incinerators.

Under these proposed applicability criteria, two types of stationary combustion turbines that are currently subject to criteria pollutant standards under subpart KKKK would not have been subject to CO_2 standards. The first type was stationary combustion turbines that are constructed for the purpose of selling and that actually sell one-third or less of their potential output or 219,000 MWh or less to the grid on a 3-year rolling average basis (*i.e.,* non-base load units). The second type was combustion turbines that actually combust 90 percent or less natural gas on a 3-year rolling average basis (*i.e.,* multi-fuel-fired units).

We proposed the electric sales criteria in part because they already exist in other regulatory contexts (*e.g.,* the coal-fired EGU criteria pollutant NSPS) and would promote consistency between regulations. Our understanding at proposal was that the percentage electric sales criterion would distinguish between non-base load units (*e.g.,* low capital cost, flexible, but relatively inefficient simple cycle units) and base load units (*i.e.,* higher capital cost, less flexible, but relatively efficient combined cycle units).

While the proposed applicability criteria did not explicitly exempt simple cycle combustion turbines from the emission standards, we concluded that, as a practical matter, the vast majority of simple cycle turbines would be excluded because they historically have operated as peaking units and, on average, have sold less than five percent of their potential electric output on an annual basis, well below the proposed one-third electric sales threshold.

a. Solicitation of comment on applicability, generally

We solicited comment on a range of issues related to applicability. In conjunction with the proposed one-third (*i.e.,* 33.3 percent) electric sales threshold, we solicited comment on a threshold between 20 to 40 percent of potential electric output. We also solicited comment on a variable percentage electric sales criterion, which would allow more efficient, lower emitting turbines to run for longer periods of operation before becoming subject to the standards of performance. Under this ''sliding scale'' approach, the percentage electric sales criterion would be based on the net design efficiency of the combustion turbine being installed. In this way, more efficient combustion turbines would be able to sell a greater portion of their potential electric output compared with less efficient combustion turbines before becoming subject to an emission standard. This approach had the benefit of incentivizing the development and installation of more efficient simple cycle combustion turbines to serve peak load.

We also solicited comment on whether the percentage electric sales criterion for stationary combustion turbines should be defined on a single calendar year basis. In addition, we solicited comment on eliminating the 219,000 MWh aspect of the total electric sales criterion to eliminate any incentive for generators to install multiple, small, less-efficient stationary combustion turbines that would be exempt due to their lower output. We further solicited comment on whether to provide an explicit exemption for all simple cycle combustion turbines regardless of the amount of electricity sold. We additionally solicited comment on how to implement the proposed electric sales, fossil fuel-use, and natural

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[529] 73 MW is equivalent to 260 GJ/h. We changed units to avoid potential confusion of MW referring to electric output rather than heat input.

gas-use criteria given that they were to be evaluated as 3-year rolling averages during the first three years of operation, and we requested comment on appropriate monitoring, recordkeeping, and reporting requirements. We specifically solicited comment on whether these proposed requirements raised implementation issues because they were based on source operation after construction has occurred.

We also solicited comment on excluding electricity sold during system emergencies from the calculation of percentage electric sales. The rationale for this exclusion was that simple cycle combustion turbines intended only for peaking applications might be required to operate above the proposed percentage electric sales threshold if a major power plant or transmission line became unexpectedly unavailable for an extended period of time. The EPA proposed that this flexibility would be appropriate if the unit were called upon to run after all other available generating assets were already running at full load.

b. Solicitation of comment on broad applicability approach

In both the January 2014 proposal for newly constructed EGUs and the June 2014 proposal for modified and reconstructed EGUs, the EPA solicited comment on finalizing a broad applicability approach instead of the proposed approach. Under the proposed approach, a stationary combustion turbine could be an affected EGU one year, but not the next, depending on the unit's actual electric sales and the composition of fuel burned. The broad applicability approach is consistent with historical NSPS applicability approaches that are based on design criteria and include different emission standards for subcategories that are distinguished by operating characteristics. Specifically, we solicited comment on whether we should completely remove the electric sales and natural gas-use criteria from the general applicability framework. Instead, the percentage electric sales and natural gas-use thresholds would serve as subcategorization criteria for distinguishing among classes of EGUs and subcategory-specific emissions standards. Under this broad applicability approach, the ''constructed for the purpose of'' component of the percentage electric sales criterion would be completely eliminated so that applicability for combustion turbines would be determined only by a unit's base load rating (*i.e.,* greater than 260 GJ/h (250 MMBtu/h)) and its capability to sell power to a utility distribution system (*i.e.,* serving a generator capable of selling more than 25 MW). In contrast to the proposed applicability criteria, under the broad applicability approach, non-base load (*e.g.,* simple cycle) and multi-fuel-fired (*e.g.,* oil-fired) combustion turbines would remain subject to the rule regardless of their electric sales or fuel use. We solicited comment on all aspects of this ''broad applicability approach,'' including the extent to which it would achieve our policy objective of assuring that owners and operators install NGCC combustion turbines if they plan to sell more than the specified electric sales threshold to the grid.

2. Comments on Applicability

This section summarizes the comments we received specific to each of the proposed applicability criteria. We also received more general comments on the scope of the proposed framework as compared to the scope of the broad applicability approach. Comments on applicability for dedicated non-fossil and CHP units are discussed in Section III.

a. Base load rating criterion

Many commenters supported a base load rating of 260 GJ/h (250 MMBtu/h) because it is generally consistent with the threshold used in states participating in the Regional Greenhouse Gas Initiative (RGGI) and under Title IV programs. Other commenters opposed the proposed applicability thresholds and stated that all new, modified, and reconstructed units that sell electricity to the grid, including small EGUs and simple cycle combustion turbines, should be affected EGUs because they would otherwise have a competitive advantage in energy markets as they would not be required to internalize the costs of compliance.

b. Total electric sales criterion

Commenters noted that the 219,000 MWh total electric sales threshold put larger combustion turbines at a competitive disadvantage by distorting the market and could have the perverse impact of increasing CO_2 emissions. These commenters noted that the 219,000 MWh total electric sales threshold would allow combustion turbines smaller than approximately 80 MW to sell more than one-third of their potential electric output, but larger, more efficient combustion turbines would still be restricted to selling one-third of their potential electric output to avoid triggering the NSPS. They argued that this would result in a regulatory incentive for generators to install multiple, less-efficient combustion turbines instead of fewer, more-efficient combustion turbines and could have the unintended consequence of increasing CO_2 emissions.

c. Percentage electric sales criterion

Commenters from the power sector generally supported a complete exemption for simple cycle turbines. These commenters stated that simple cycle turbines are uniquely capable of achieving the ramp rates (the rate at which a power plant can increase or decrease output) necessary to respond to emergency conditions and hourly variations in output from intermittent renewables. Commenters noted that simple cycle combustion turbines serve a different purpose than NGCC power blocks. In addition, commenters noted that electricity generation dispatch is based on the incremental cost to generate electricity and that because NGCC units have a lower incremental generation cost than simple cycle units, economics will drive the use of NGCC technologies over simple cycle units. However, commenters also stated that historic simple cycle operating data may not be representative of future system requirements as coal units retire, generation from intermittent renewable generation increases, and numerous market and regulatory drivers impact plant operations. In the absence of a complete exemption, these commenters supported a percentage electric sales threshold between 40 to 60 percent of a unit's potential electric output.

Some commenters said that because the proposed percentage electric sales criterion applied over a three-year period, it would adversely affect grid reliability because operators conservatively would hedge short-term operating decisions to ensure that they have sufficient capacity to respond to unexpected scenarios during future compliance periods when the demand for electricity is higher. These commenters were concerned that such compliance decisions would drive up the cost of electricity as the most efficient new units are taken out of service to avoid triggering the NSPS and older, less efficient units with no capacity factor limitations are ramped up instead.

Some commenters supported the sliding-scale approach (*i.e.,* a percentage electric sales threshold based on the design efficiency of the combustion turbine) and stated that incentives for manufacturers to develop (and end users to purchase) higher efficiency combustion turbines could help mitigate concerns about a monolithic national constraint on simple cycle capacity factors.

In contrast, others commented that fast-start NGCC units intended for peaking and intermediate load applications can achieve comparable ramp rates to simple cycle combustion turbines, but with lower CO_2 emission rates. These commenters said that simple cycle turbines should be restricted to their historical role as true peaking units and that the proposed one-third electric sales threshold provided sufficient flexibility. Some commenters suggested that the one-third electric sales threshold could be reduced to 20 percent or lower without adverse impacts on grid reliability.

Commenters noted that a complete exclusion for simple cycle turbines would create a regulatory incentive for generators to install and operate less efficient unaffected units instead of more efficient affected units, thereby increasing CO_2 emissions. According to these commenters, any applicability distinctions should be based on utilization and function rather than purpose or technology.

Commenters in general supported the use of 3-year rolling averages instead of a single-year average for the percentage and total electric sales criteria because, in their view, the 3-year rolling averages would provide a better overall picture of normal operations. Some commenters stated that a rolling 12-month or calendar-year average could be severely skewed in a given year because of unforeseen or unpredicted events. They said that using a 3-year averaging methodology would provide system operators with needed flexibility to dispatch simple cycle units at higher than normal capacity factors. In contrast, some commenters stated that, because capacity is forward-looking (*e.g.,* payments for capacity are often made several years in advance), the 3-year averaging period provides limited benefit because owner/operators need to reserve the ability to respond to unforeseen events.

Commenters noted that potential compliance issues could result from the inconsistent time frame between the 3-calendar-year applicability period and the 12-operating-month compliance period. For example, a facility could sell more than one-third of its potential electric output over a 3-year period, but sell less than one-third of its potential electric output during any given 12-operating-month compliance period within that 3-year period. During a 12-operating-month period with electric sales of less than one-third of potential electric output, a unit could be operating for long periods at part load and have multiple starts and stops. These operating conditions have the potential to increase CO_2 emissions, regardless of the deign efficiency of the turbine. Therefore, a unit could have an emission rate in excess of the proposed standard.

Regarding the relationship between the percentage electric sales criterion and system emergencies, multiple commenters supported exclusion of electricity generated as a result of a system emergency from counting towards net sales. These commenters stated that the exclusion was appropriate because the benefits of operating these units to generate electrical power during emergency conditions would outweigh any adverse impacts from short-term increases in CO_2 emissions. One commenter stated that, in addition to declared grid emergencies, other circumstances might warrant emergency exemption under the rule, including extreme market conditions, limitations on fuel supply, and reliability responses.

Multiple commenters opposed the exclusion of system emergencies when calculating a source's percentage electric sales for applicability purposes because NSPS must apply continuously, even during system emergencies. These commenters stated that the EPA does not have the authority under the CAA to suspend the applicability of a standard during periods of system emergency. Some commenters stated that an exclusion would be unnecessary because the EPA Assistant Administrator for Enforcement has the authority to advise a source that the government will not sue the source for taking certain actions during an emergency. Commenters said that this enforcement discretion approach has provided prompt, flexible relief that is tailored to the needs of the particular emergency and the communities being served and is only utilized where the relief will address the particular emergency at hand.

Commenters added that this enforcement discretion approach is consistent with the CAA's mandate that emission limits apply continuously and provide safeguards against abuse. One commenter stated that emergencies happen rarely and typically last for short periods, that the proposed percentage electric sales threshold would allow a source to operate at its full rated capacity for up to 2,920 hours per year without triggering applicability, and that the potential occurrence of grid emergencies would represent a tiny fraction of this time. Another commenter stated that no emergency short of large scale destruction of power generating capacity by terrorism, war, accident, or natural disaster could justify operating a peaking unit above a 10-percent capacity factor on a 3-year rolling average.

d. Broad applicability approach

In response to the EPA's request for comments on whether the proposed applicability requirements that retrospectively look back at actual events (*i.e.,* the electric sales and fuel use criteria) would create implementation issues, several permitting authorities opposed the provisions because units could be subject to coverage one year but not the next, resulting in compliance issues and difficulties in determining proper pre-construction and operating permit conditions. These permitting authorities suggested that in order for a source to avoid applicability, the source should be subject to a federally enforceable permit condition with associated monitoring, recordkeeping, and reporting conditions for assessing applicability on an ongoing basis. Other commenters stated that an applicability test that concludes after construction and operation have commenced is inconsistent with the general purpose of an applicability test—to provide clear and predictable standards of performance for new sources that would apply when they begin operations.

Some commenters opposed the proposed retrospective applicability criteria related to actual output supplied during a preceding compliance period because EGUs must know what performance standards will apply to them during the licensing process, and such criteria do not allow the permitting authority and the public to know in advance whether an emission standard applies to a proposed new unit. Other commenters said that EGUs undergoing permitting should be allowed to request limits in their operating permit conditions in order to remain below the applicability thresholds, as this methodology is consistent with the pre-construction permitting requirements in many federally approved SIPs and the current approach under the Title V permitting program.

Many commenters stated a preference for the ''proposed applicability approach'' over the ''broad applicability approach.'' These commenters did not think it was necessary to require non-base load or multi-fuel-fired combustion turbines to be subject to emission standards. They stated that there is no justification for imposing burdensome monitoring, reporting, and recordkeeping requirements that would have no environmental benefit (*i.e.,* would not reduce CO_2 emissions) because these units would be subject to ''no emissions standards.'' Other commenters supported the broad applicability approach and stated that all new, modified, and reconstructed units that sell electricity to the grid, including small EGUs, oil-fired combustion turbines, and simple cycle combustion turbines should be affected EGUs because they would otherwise have a competitive advantage in energy markets as they would not be required to internalize the costs of compliance.

In contrast, to preserve the discretion of state planners under section 111(d), many other commenters supported the broad applicability approach and the inclusion of new simple cycle units within the scope of the section 111(b) emission standards so that similar, existing simple cycle units could be subject to the 111(d) standards. Numerous other commenters stated that all units that sell electricity to the grid should be subject to a standard, including simple cycle units, because they view the utility grid as a single integrated system and that doing so may simplify development of future frameworks for cost-effective carbon reductions from existing units, such as frameworks based on system-wide approaches.

3. Final Applicability Criteria and Rationale

Based on our consideration of the comments received related to the proposed applicability criteria and practical implementation issues, we are revising how those criteria will be implemented. The final applicability criteria for combustion turbines are generally consistent with the broad applicability approach on which we solicited comment. Section VIII of this preamble presents each proposed applicability criterion together with the form of the criterion in the final rule. The final general applicability framework includes the proposed criteria based on the combustion turbine's base load rating and the combustion turbine's total electric sales capacity. The final general applicability framework also includes multiple exemptions that are relevant to combustion turbines: combustion turbines that are not connected to natural gas pipelines; CHP facilities with federally enforceable limits on total electric sales; dedicated non-fossil units with federally enforceable limits on the use of fossil fuels; and municipal waste combustors and incineration units.

The final applicability framework reflects multiple variations from the proposal that are responsive to public comments. First, consistent with the broad applicability approach, we are finalizing the percentage electric sales and natural gas-use thresholds as subcategorization criteria instead of as applicability criteria. In addition, for non-CHP combustion turbines, we are eliminating the proposed 219,000 MWh total electric sales criterion. Finally, we are eliminating the proposed ''constructed for the purpose of'' qualifier for the total and percentage electric sales criteria. We are also not finalizing CO_2 standards for dedicated non-fossil fuel-fired or industrial CHP combustion turbines. The rationale for not finalizing CO_2 standards for dedicated non-fossil and industrial CHP units is discussed in more detail in Section III.

The EPA agrees with commenters that the NSPS applicability framework should be structured so that permitting authorities, the regulated community, and the public can determine what standards apply prior to a unit having commenced construction. With this in mind, the EPA has concluded that the proposed fossil fuel-use, natural gas-use, percentage electric sales, and total electric sales applicability criteria for combustion turbines are not ideal approaches. Because applicability determinations based on these criteria could change from year to year (*i.e.,* units could move in and out of coverage each year depending on actual operating parameters), some operators would not know the extent of their compliance obligations until after the compliance period.

Further, from a practical implementation standpoint, existing permitting rules generally require pre-construction permitting authorities to include enforceable conditions limiting operations such that unaffected units will not trigger applicability thresholds. Such conditions are often called ''avoidance'' or ''synthetic minor'' conditions, and these conditions typically include ongoing monitoring, recordkeeping, and reporting requirements to ensure that operations remain below a particular regulatory threshold.

The following sections provide further discussion of the final general applicability criteria and the rationale for changing certain proposed applicability criteria to subcategorization criteria.

a. Base load rating criterion

We are retaining the applicability criterion that a combustion turbine must be capable of combusting more than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel. We revised the proposed 73 MW form of the base load rating criterion to 260 GJ/h because some commenters misinterpreted the 73 MW form (which is mathematically equivalent to 250 MMBtu/h) as the electrical output rating of the generator. This change is a non-substantive unit conversion intended to limit misinterpretation. While some commenters suggested that we expand this applicability criterion to cover smaller EGUs as well, we did not propose to cover smaller units. Because smaller units emit relatively few CO_2 emissions compared to larger units and because we currently do not have enough information to identify an appropriate BSER for these units, we are not finalizing CO_2 standards for smaller units.

b. Total electric sales criterion

The proposed 219,000 MWh total sales criterion was based on a 25 MW unit operating at base load the entire year (*i.e.,* 25 MW * 8,760 h/y = 219,000 MWh/y). This criterion was included in the original subpart Da coal-fired EGU criteria pollutant NSPS. Coal-fired EGUs tend to be much larger than 25 MW, and the criterion's primary purpose was to exempt industrial CHP facilities from the criteria pollutant NSPS. In the context of combustion turbines, however, commenters expressed concerns that the 219,000 MWh electric sales threshold would actually encourage owners and operators to install multiple, smaller, less-efficient simple cycle combustion turbines instead of a single, larger, more-efficient simple cycle turbine. The reason for this is that the 219,000 MWh threshold would allow smaller simple cycle combustion turbines of less than 80 MW to sell significantly more electricity relative to their potential electric output than larger turbines. Many commenters also indicated that having the flexibility to operate a simple cycle turbine at a higher capacity factor is important because it allows for capacity payments from the transmission authority. In light of these comments, we are not finalizing the 219,000 MWh total electric sales criterion for non-CHP combustion turbines. Instead, we are finalizing a criterion that will exempt combustion turbines that do not have the ability to sell at least 25 MW to the grid. This approach will maintain our goal of exempting smaller EGUs, while avoiding the perverse environmental incentives mentioned by the commenters. As explained in Section III, however, industrial CHP units are sized based on demand for useful thermal output, so there is less of an incentive for owners and operators to install multiple smaller units. Therefore, we are maintaining the 219,000 MWh total electric sales criterion for CHP units.

c. Percentage electric sales criterion

Commenters generally opposed the proposed percentage electric sales criterion approach because it was based in part on actual electric sales, meaning applicability could change periodically (*i.e.,* a unit's electric sales may change over time, rising above and falling below the electric sales threshold). The EPA agrees this situation is not ideal. To avoid situations in which applicability changes from year to year, we first considered two approaches using permit restrictions. Under the first approach, a standard would apply to all sources with permit restrictions mandating electric sales above a threshold (*i.e.,* an approach that closely mirrors the proposed percentage electric sales criterion). Under the second approach, a standard would apply to all sources without permit restrictions limiting electric sales to a level below that threshold (*i.e.,* effectively identifying non-base load units and excluding them from applicability). As stated in the proposal, we did not think it was critical to include peaking and cycling units because peaking turbines operate less and because it would be much more expensive to lower their emission profile to that of a combined cycle power plant or a coal-fired plant with CCS.

The first approach is not practical, however, because new combustion turbines could avoid applicability by simply not having a permit restriction at all. Moreover, even if a combustion turbine were subject to the restriction, it could violate its permit if it did not operate enough to sell the requisite amount of electricity. This would be nonsensical, especially because system demand would not always be sufficient to allow all permitted units to operate above the threshold. Therefore, we rejected the first permitting approach.

In contrast, the second approach would be a viable method for identifying and exempting peaking units from applicability. However, there are multiple drawbacks to such an applicability approach. First, this approach would subject those turbines without a permit restricting electric sales to the final emission standards, which raises concerns as to whether turbines with lower actual sales could achieve the standards. For example, new NGCC units tend to dispatch prior to older existing units and will generally operate for extended periods of time near full load and sell electricity above the percentage electric sales threshold. However, as NGCC units age, they tend to start and stop more frequently and operate at part load. Yet, even if these units sell below the percentage electric sales threshold, they would still be affected units if they did not take a permit restriction. As commenters noted, part-load operation and frequent starts and stops can reduce the efficiency of a combustion turbine. While we are confident that our final standards for base load natural gas-fired combustion turbines can be achieved by units serving either base or intermediate load, we are not as confident that affected NGCC units that might someday be operated as non-base load units (*e.g.,* as NSPS units age, their incremental generating costs will tend to be higher than newer units and they will dispatch less) could achieve the standards.

More importantly, however, we are concerned that using a permitting approach for the percentage electric sales criterion would create problems due to the interaction between 111(b) and 111(d). Under the second permitting approach we considered, units with low electric sales would be excluded from applicability, while units with high electric sales would be included. While these low-electric sales units would generally be simple cycle combustion turbines and the high-electric sales units would generally be NGCC combustion turbines, this would not always be the case. In contrast, we are finalizing an applicability approach in the 111(d) emission guidelines that is based on a combustion turbine's design characteristics rather than electric sales. Simple cycle combustion turbines are excluded from applicability, while NGCC units are included. As a result, the universe of sources covered by the 111(b) standards would not necessarily be the same universe of sources covered by the 111(d) standards.

To resolve this issue, we considered whether we could change the 111(d) applicability criteria to be based on historical operation rather than design characteristics. For example, if an existing combustion turbine had historically sold less than one-third of its potential output to the grid, then it would be exempt from the emission guidelines. However, many existing NGCC units have historically sold less than this amount of electricity, meaning that they would not be subject to the rule. We ran into similar issues when considering other thresholds. For example, a percentage electric sales threshold of 10 percent would still exempt roughly 5 percent of existing NGCC units from 111(d), while simultaneously raising achievability concerns with the 111(b) standard. Moreover, even if we had finalized 111(d) applicability criteria based on historical operations, existing NGCC units could have decided to take a permit restriction limiting their electric sales going forward to avoid applicability. Under any of these scenarios, our goals with respect to 111(d) would not be accomplished.

To avoid this result, the EPA has concluded that it is appropriate to finalize the broad applicability approach and set standards for combustion turbines regardless of what percentage of their potential electric output they sell to the grid. To accommodate the continued use of simple cycle and fast-start NGCC combustion turbines for peaking and cycling applications, however, the EPA has subcategorized natural gas-fired combustion turbines based on a variation of the proposed percentage electric sales criterion. Specifically, and as explained in more detail in Section IX.B.2, we are finalizing the sliding-scale approach on which we solicited comment.

d. Natural gas-use criterion

Similar to the proposed electric sales criteria, commenters generally opposed the proposed natural gas-use criterion being based on actual operating parameters. As with the electric sales criteria, the EPA agrees that applicability that can switch periodically due to operating parameters is not ideal. The EPA evaluated two approaches for implementing the intent of the proposed natural gas-use criterion (*i.e.,* to exclude non-natural gas-fired combustion turbines) through operating permit restrictions. Under the first approach, an emission standard would apply to all combustion turbines with a permit restriction mandating that natural gas contribute over 90 percent of total heat input.[530] Under the second approach, an emission standard would apply to all combustion turbines without a permit restriction limiting natural gas use to 90 percent or less of total heat input.[531] As with the percentage electric sales criterion, the first approach is not practical because combustion turbines could avoid

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[530] This approach could also be written as ''an emission standard would apply to all combustion turbines with a permit restriction limiting the use of non-natural gas fuels to 10 percent or less of the total heat input.'' Applicability could then be avoided by simply being permitted to burn non-natural gas fuels for more than 876 hours per year even if they actually intended to seldom, if ever, combust the alternate fuels.

[531] This approach could also be written as ''an emission standard would apply to all combustion turbines without permit restrictions mandating that non-natural gas use contribute over 10 percent or more of total heat input.''

applicability by simply not having a permit that requires the use of more than 90 percent natural gas, even if they intend to only burn natural gas. We disregarded this approach because it would essentially provide a pathway for all NGCC units to avoid applicability under both 111(b) and 111(d). The second approach is problematic because operating permit restrictions to improve air quality are typically written to limit high emission activities (*e.g.,* limiting the use of distillate oil to 500 hours annually), not to limit lower emitting activities. This approach could lead to perverse environmental impacts by incentivizing the use of non-natural gas fuels, which would typically result in higher CO_2 emissions. Furthermore, the second approach would not limit the fuels that can be burned by affected units (*i.e.,* combustion turbines not required to use non-natural gas fuels) and would continue to cover combustion turbines even when they burn over 10 percent non–natural gas fuels. Because all non-natural gas fuels except H_2 have CO_2 emission rates higher than natural gas, this approach would exacerbate the concerns raised by commenters about the achievability of the 111(b) requirements when burning back up fuels.

In light of these issues, the EPA has concluded that permit restrictions are not an ideal approach to distinguishing between natural gas-fired and multi-fuel-fired combustion turbines and are finalizing a variation of the broad applicability approach. The EPA has concluded that the only practical approach to implement the natural gas-use criterion is to look at the turbine's physical ability to burn natural gas. Therefore, we are not finalizing CO_2 standards for combustion turbines that are not capable of firing any natural gas (*i.e.,* not connected to a natural gas pipeline). From a practical standpoint, the burners of most combustion turbines can be modified to burn natural gas, so this exemption is essentially limited to combustion turbines that are built in remote or offshore locations without access to natural gas. Consistent with the broad applicability approach, we are finalizing standards for all other combustion turbines, but are subcategorizing between natural gas-fired turbines and multi-fuel-fired turbines. Specifically, and as explained in more detail in Section IX.B.3, we are distinguishing between these classes of turbines based on whether they burn greater than 90 percent natural gas or not.

B. Subcategories

We are finalizing a variation of the broad applicability approach for combustion turbines where the percentage electric sales and natural gas-use criteria serve as thresholds that distinguish between three subcategories. These subcategories are base load natural gas-fired units, non-base load natural gas-fired units, and multi-fuel-fired units. Under the final subcategorization approach, multi-fuel-fired combustion turbines are distinguished from natural gas-fired turbines if fuels other than natural gas (*e.g.,* distillate oil) supply 10 percent or more of heat input. Natural gas-fired turbines are further subcategorized as base load or non-base load units based on the percentage electric sales criterion. The percentage electric sales threshold that distinguishes base load and non-base load units is based on the specific turbine's design efficiency (*i.e.,* the sliding-scale approach). The percentage electric sales threshold is capped at 50 percent.

This section describes comments we received regarding the proposed size-based subcategories and our rationale for not finalizing them. In addition, it describes comments we received regarding sales-based subcategories and our rationale for adopting the sliding scale to distinguish between subcategories. Finally, it describes comments we received regarding fuel-based subcategories and our rationale for adopting fuel-based subcategories.

1. Size-Based Subcategories

At proposal, the EPA identified two size-based subcategories: (1) large natural gas-fired stationary combustion turbines with a base load rating greater than 850 MMBtu/h and (2) small natural gas-fired stationary combustion turbines with a base load rating of 850 MMBtu/h or less. The EPA received numerous comments regarding our proposal to subcategorize combustion turbines by size. Some commenters agreed with the 850 MMBtu/h cut-point between large and small units, some suggested increasing it to 1,500 MMBtu/h, and others suggested eliminating size-based subcategorization altogether. For example, some commenters stated that the 850 MMBtu/h cut-point was inappropriate because it was originally calculated based on NO_X performance, not CO_2 performance. These commenters stated that 850 MMBtu/h was not a logical demarcation between more efficient and less efficient combustion turbines, but rather would divide the units into arbitrary size classifications. These commenters suggested that 1,500 MMBtu/h would be a better cut-point because data reported to *Gas Turbine World* (GTW) showed that new combustion turbines are not currently offered with a heat input rating between 1,300 MMBtu/h and 1,800 MMBtu/h, so the higher cut-point would more accurately reflect when more efficient technologies are available.

In contrast, other commenters said that differentiation between small and large combustion turbines was not justified at all because many of the same efficiency technologies that reduce the emission rates of larger units could be incorporated into smaller units (*e.g.,* upgrades that increase the turbine engine operating temperature, increase the turbine engine pressure ratio, or add multi-pressure steam and a steam reheat cycle). These commenters also said that separate standards for small and large turbines would undermine the incentive for technology innovation, which they described as a key purpose of the NSPS program, and that relaxing standards for smaller units would discourage investment in more efficient technologies, resulting in increased CO_2 emissions. These commenters recommended that the limit for both large and small units be no higher than 1,000 lb CO_2/MWh-g.

After evaluating these comments, the EPA has decided not to subcategorize combustion turbines based on size for several reasons. First, the heat input values listed in *Gas Turbine World* do not include potential heat input from duct burners.[532] Because the heat input from duct burners is necessary to accurately determine potential electric output, our definition of ''base load rating'' includes the heat input from any installed duct burners. The EPA reviewed the heat input data for existing NGCC units that has been submitted to CAMD. These data include the heat input from duct burners and show that multiple NGCC power blocks have been built in the past with heat input capacities that fall within the range that commenters suggested new turbines are not offered. Therefore, the EPA has concluded that the regulated community uses various sizes of NGCC turbines and when the heat input from duct burners is included, there is no clear break between the NGCC unit sizes that could distinguish between small and large units. In fact, subcategorizing

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[532] Duct burners are optional supplemental burners located in the HRSG that are used to generate additional steam. Heat input to duct burners could in theory be twice that of the combustion turbine engine, but are more commonly sized at 10 to 30 percent of the heat input to the combustion turbine engine.

by size could unduly influence the development of future NGCC offerings because manufacturers could be incentivized to design new products at the top end of the small subcategory to take advantage of the less stringent emission standard.

Second, commenters suggested that a cut-point of 1,500 MMBtu/h reflects when more efficient technologies become available. However, when we reviewed actual operating data and design data, we only found a relatively weak correlation between turbine size and CO_2 emission rates and did not see a dramatic drop in CO_2 emission rates at 1,500 MMBtu/h. The variability of emission rates among similar size units far exceeds any difference that could be attributed to a difference in size. In addition, the most efficient one-to-one configuration NGCC power block with a base load rating of 1,500 MMBtu/h or less has a design emission rate of the 767 lb CO_2/MWh-n (984 MMBtu/h). The most efficient one-to-one configuration NGCC power block with a base load rating just greater than 1,500 MMBtu/h has a design emission rate of 772 lb CO_2/MWh-n (1,825 MMBtu/h). Because the smaller unit has a lower design emission rate than the larger unit, increasing the cut-point does not make sense.

Finally, the EPA has concluded that, while certain smaller NGCC designs may be less efficient than larger NGCC designs, most existing small units have demonstrated emission rates below the range of emission rates on which we solicited comment. We have concluded that the lower design efficiencies of some small NGCC units are primarily related to model-specific design choices in both the turbine engine and HRSG, not an inherent limitation in the ability of small NGCC units to have comparable efficiencies to large NGCC units. Specifically, manufacturers could improve the efficiency of the turbine engine by using turbine engines with higher firing temperatures and high compression ratios and could improve the efficiency of the steam cycle by switching from single or double-pressure steam to triple-pressure steam and adding a reheat cycle. For all of these reasons, we have decided against subcategorizing combustion turbines based on size. Our rationale for setting a single standard for small and large combustion turbines is explained in more detail in Section IX.D.3.a below.

2. Sales-Based Subcategories

As described above in Section IX.A.3.c, the final applicability criteria do not include an exemption for non-CHP units based on actual electric sales or permit restrictions limiting the amount of electricity that can be sold. Instead, we are finalizing the percentage electric sales criterion as a threshold to distinguish between two natural gas-fired combustion turbine subcategories. The industry uses a number of terms to describe combustion turbines with different operating characteristics based on electric sales (*e.g.,* capacity factors). Combustion turbines that operate at near-steady, high loads are generally referred to as ''base load'' or ''intermediate load'' units, depending on how many hours the units operate annually. Combustion turbines that operate continuously with variable loads that correspond to variable demand are referred to as ''load following'' or ''cycling'' units. Combustion turbines that only operate during periods with the highest electricity demand are referred to as ''peaking'' units. However, it is difficult to characterize a particular unit using just one of these terms. For example, a particular unit may serve as a load following unit during winter, but serve as a base load unit during summer. In addition, none of these terms has a precise universal definition. In this preamble, we refer to the subcategory of combustion turbines that sell a significant portion of their potential electric output as ''base load units.'' This subcategory includes units that would colloquially be referred to as base load units, as well as some intermediate load and load following units. We refer to all other units as ''non-base load units.'' This subcategory includes peaking units, as well as some load following and intermediate load units. The threshold that distinguishes between these two subcategories is determined by a unit's design efficiency and varies from 33 to 50 percent, hence the term ''slide scale'' approach.

Numerous commenters supported three sales-based subcategories for peaking, intermediate load, and base load units. These commenters said that each subcategory should be distinguished by annual hours of operation and that each should have a different BSER and emission standard. Other commenters opposed the tiered approach. These commenters said that separate standards for different operating conditions would be complicated to implement and enforce, while providing few benefits. These commenters said that a tiered approach could also have the unintended consequence of encouraging less efficient technologies because it would create a regulatory incentive to install lower-capital-cost, less-efficient units that would operate under the percentage electric sales threshold instead of higher-capital-cost, more-efficient units that would operate above the threshold.

After evaluating these comments, the EPA has concluded that it is appropriate to adopt a two-tiered subcategorization approach based on a percentage electric sales threshold to distinguish between non-base load and base load units. While we agree with commenters that separate standards for peaking, intermediate, and base load units is attractive on the surface, we ultimately concluded that a three-tiered approach is not appropriate for several reasons. First, the increased generation from renewable sources that is anticipated in the coming years makes it very difficult to determine appropriate thresholds to distinguish among peaking, intermediate, and base load subcategories. Indeed, the boundaries between these demand-serving functions may blur or shift in the years to come. The task is further complicated because each transmission region has a different mix of generation technologies and load profiles with different peaking, intermediate, and base load requirements.

Second, there are only two distinct combustion turbine technologies—simple cycle units and NGCC units. In theory, the BSER for the intermediate load subcategory could be based on high-efficiency simple cycle units or fast-start NGCC units, but these are variations on traditional technologies and not necessarily distinct. Moreover, we do not have specific cost information on either high-efficiency simple cycle turbines or fast-start NGCC units, so our ability to make cost comparisons to conventional designs is limited.

Finally, even if we could identify appropriate sales thresholds to distinguish between peaking, intermediate load, and base load subcategories, we do not have sufficient information to establish a meaningful output-based standard for an intermediate load subcategory at this time. In the transition zone from peaking to base load operation (*i.e.,* cycling and intermediate load), combustion turbines may have similar electric sales, but very different operating characteristics. For example, despite having similar sales, one unit might have relatively steady operation for a short period of time, while another could have variable operation throughout the entire year. The latter unit would likely have a higher CO_2 emission rate. For all of these reasons, the EPA has concluded that we do not have sufficient information at this time to establish three sales-based subcategories.

Instead, as we explained above, we are finalizing two sales-based subcategories. To determine an appropriate threshold to distinguish between base load and non-base load units, the EPA considered the important characteristics of the combustion turbines that serve each type of demand. For non-base load units, low capital costs and the ability to start, stop, and change load quickly are key. Simple cycle combustion turbines meet these criteria and thus serve the bulk of peak demand. In contrast, for base load units, efficiency is the key consideration, while capital costs and the ability to start and stop quickly are less important. While NGCC units have relatively high capital costs and are less flexible operationally, they are more efficient than simple cycle units. NGCC units recover the exhaust heat from the combustion turbine with a HRSG to power a steam turbine, which reduces fuel use and CO_2 emissions by approximately one-third compared to a simple cycle design. Consequently, base load units use NGCC technology. Because simple cycle turbines have historically been non-base load units, we have concluded that it is appropriate to distinguish between the non-base load and base load subcategories in a way that recognizes the distinct roles of the different turbine designs on the market.

The challenge, however, is setting a threshold that will not distort the market. The future distinction between non-base load and base load units is unclear. For example, some commenters indicated that increased generation from intermittent renewable sources has created a perceived need for additional cycling and load following generation that will operate between the traditional roles of peaking and base load units. To fulfill this perceived need, some manufacturers have developed high-efficiency simple cycle turbines. These high-efficiency turbines have higher capital costs than traditional simple cycle turbine designs, but maintain similar flexibilities, such as the ability to start, stop, and change load rapidly. Other manufacturers have developed fast-start NGCC turbines to fill the same role. These newer NGCC designs have lower design efficiencies than NGCC designs intended to only operate as base load units, but are able to startup more quickly to respond to rapid changes in electricity demand. As a result of these new technological developments, both high-efficiency simple cycle and fast-start NGCC units can be used for traditional peaking applications, as well as for higher capacity applications, such as supporting the growth of intermittent renewable generation.

With the changing electric sector in mind, we set out to identify an appropriate percentage electric sales threshold to distinguish between non-base load and base load natural gas-fired units. Two factors were of primary importance to our decision. First, the threshold needed to be high enough to address commenters' concerns about the need to maintain flexibility for simple cycle units to support the growth of intermittent renewable generation. Second, the threshold needed to be low enough to avoid creating a perverse incentive for owners and operators to avoid the base load subcategory by installing multiple, less efficient turbines instead of fewer, more efficient turbines.

To determine the potential impact of intermittent renewable generation on the operation of simple cycle units, we examined the average electric sales of simple cycle turbines in the lower 48 states between 2005 and 2014 using information submitted to CAMD. We combined this data with information reported to the EIA on total in-state electricity generation, including wind and solar, from 2008 through 2014. We focused on data from the Southwest Power Pool (data approximated by EGUs in Nebraska, Kansas, and Oklahoma), Texas, and California. All of these regions have relatively large amounts of generation from wind and solar and experienced increases in the portion of total electric generation provided by wind and solar during the 2008–2014 period.

a. Southwest Power Pool

The portion of in-state generation from wind and solar in the Southwest Power Pool increased from 3 to 16 percent between 2008 and 2014. The average growth rate of wind and solar was 28 percent, while overall electricity demand grew 1 percent annually on average. Based on statements in some of the comments, we expected to see a large change in the operation of simple cycle turbines in this region. However, the average electric sales from simple cycle turbines only increased at an annual rate of 1.7 percent, and remained essentially unchanged at 3 percent of potential electric output between 2008 and 2014. Total generation from simple cycle turbines in the Southwest Power Pool increased slightly more, at an annual rate of 2.5 percent, which was the result of additional simple cycle capacity being added to address increased electricity demand.

This lack of a significant change in the operation of simple cycle turbines could be explained by the Southwest Power Pool's relatively large amount of exported power. If most of the region's renewable generation was being exported, the intermittent nature of this power would primarily impact other transmission regions. An alternate explanation, however, is that other generating assets are flexible enough to respond to the intermittent nature of wind and solar generation and that simple cycle turbines are not necessary to back up these assets to the degree some commenters suggested. If this is the case, then new simple cycle turbines may primarily continue to fill their historical role as peaking units going forward, while other technologies, such as fast-start NGCC units, may provide the primary back up capacity for new wind and solar.

b. Texas

The portion of in-state generation from wind and solar in Texas increased from 4 to 9 percent between 2008 and 2014. The average growth rate of wind and solar was 13 percent, while overall demand grew at an average rate of 2 percent annually. Similar to the Southwest Power Pool, the average electric sales of simple cycle turbines has remained relatively unchanged. In fact, the average electric sales of these turbines decreased at an annual rate of 1.1 percent. Total generation from simple cycle turbines increased at an annual rate of 6.6 percent, however, due to simple cycle capacity additions that occurred at approximately four times the rate one would expect from the growth in overall demand.

The most likely technologies to back up intermittent renewable generation have low incremental generating costs and can start up and stop quickly. Highly efficient simple cycle units meet these criteria. As such, the EPA has concluded that the most efficient simple cycle turbines in a given region are the most likely to support intermittent renewable generation. Focusing on these simple cycle turbines will address concerns raised by commenters about the future percentage electric sales of highly efficient simple cycle turbines and give an indication of the impact of increased renewable generation on non-base load units intended to back up wind and solar. There are two highly efficient intercooled simple cycle turbines installed in Texas. These two combustion turbines sell an average of 10 percent of their potential electric output annually, compared to an average of 3 percent for the remaining simple cycle turbines. No simple cycle turbine in Texas sold more than 25 percent of its potential electric output annually. The rapid growth in simple cycle capacity, but not overall capacity factors, could indicate that the additional generation assets are providing firm capacity for intermittent generation sources such as wind and solar, but that capacity is infrequently required. Based on the data, even highly efficient simple cycle turbines are expected to continue to sell less than one-third of their potential electric output.

c. California

The portion of in-state generation from wind and solar in California increased from 3 to 11 percent between 2008 and 2014. The average growth rate of wind and solar was 25 percent, while overall demand has remained stable. The operation of simple cycle turbines in California has changed more significantly than in the other evaluated regions. The average electric sales from simple cycle turbines increased from 5.1 to 5.9 percent, an annual rate increase of 4.5 percent. As in Texas, considerable additional simple cycle capacity has been added in recent years. The total capacity of simple cycle turbines is increasing at 15 percent annually even though overall demand has remained relatively steady. In addition, the newest simple cycle turbines are operating at higher capacity factors than the existing fleet of simple cycle turbines, resulting in an average increase in generation from simple cycle turbines of 21 percent. Many of the new additions are intercooled simple cycle turbines that may have been installed with the specific intent to back up wind and solar generation.

The average electric sales for the intercooled turbines ranged from 3 to 25 percent, with a 7 percent average. No simple cycle turbines in California have sold more than one-third of their potential electric output on an annual basis. The operation of simple cycle turbines that existed prior to 2008 has not changed significantly. Average electric sales for these turbines increased at an annual rate of 0.1 percent. This indicates that support for new renewable generation is being provided by new units and not by the installed base of simple cycle units. These units are still serving their historical role of providing power during peak periods of demand.

Based on our data analysis, the proposed one-third electric sales threshold would appear to offer sufficient operational flexibility for new simple cycle turbines. Existing NGCC units, other generation assets, and demand-response programs are currently providing adequate back up to intermittent renewable generation. In the future, however, existing NGCC units will likely operate at higher capacity factors. They will therefore be less available to provide back up power for intermittent generation. In addition, the amount of power generated by intermittent sources is expected to increase in the future. Both of these factors could require additional flexibility from the remaining generation sources to maintain grid reliability.

Even though fast-start NGCC units, reciprocating internal combustion engines, energy storage technologies, and demand-response programs are promising technologies for providing back up power for renewable generation, none of them historically have been deployed in sufficient capacity to provide the potential capacity needed in the future to facilitate the continued growth of renewable generation. While we anticipate that state and federally issued permits for new electric generating sources will consider the CO_2 benefits of these technologies compared to simple cycle turbines, the EPA has concluded at this time that it is appropriate to finalize a percentage electric sales threshold that provides additional flexibility for simple cycle turbines.

Specifically, we have concluded that a percentage electric sales threshold based on a unit's design net efficiency at standard conditions is appropriate. This is the sliding-scale approach on which we solicited comment. Several commenters supported this approach because it provides sufficient operational flexibility for new simple cycle and fast-start NGCC combustion turbines and simultaneously promotes the installation of the most efficient generating technologies. By allowing more efficient turbines to sell more electricity before becoming subject to the standard for the base load subcategory, the sliding scale should reduce the perverse incentive for owners and operators to install more lower-capital-cost, less-efficient units instead of fewer higher-capital-cost, more-efficient units. At the same time, the sliding scale should incentivize turbine manufacturers to design higher efficiency simple cycle turbines that owners and operators can run more frequently.

The net design efficiencies for aeroderivative simple cycle combustion turbines range from approximately 32 percent for smaller designs to 39 percent for the largest intercooled designs. The net design efficiencies of industrial frame units range from 30 percent for smaller designs to 36 percent for the largest designs. These efficiency values follow the methodology the EPA has historically used and are based on the higher heating value (HHV) of the fuel. In contrast, combustion turbine vendors in the U.S. often quote efficiencies based on the lower heating value (LHV) of the fuel. The LHV of a fuel is determined by subtracting the heat of vaporization of water vapor generated during combustion of fuel from the HHV. For natural gas, the LHV is approximately 10 percent lower than the HHV. Therefore, the corresponding LHV efficiency ranges would be 35 to 44 percent for aeroderivative designs and 33 to 40 percent for frame designs. We considered basing the percentage electric sales threshold on both the HHV and LHV. The EPA typically uses the HHV, but in light of commenters' concerns regarding uncertainty in the operation of non-base load units in the future, we opted to be conservative and use the LHV efficiency.

We anticipate that high-efficiency simple cycle and fast-start NGCC turbines will make up the majority of new capacity intended for non-base load applications. Based on the sliding-scale approach, owners and operators of new simple cycle combustion turbines will be able to sell between 33 to 44 percent of the turbine's potential electric output. Our analysis showed that 99.5 percent of existing simple cycle turbines have not sold more than one-third of their potential electric output on an annual basis. In addition, 99.9 percent of existing simple cycle turbines have not sold more than 36 percent of their potential electric output on an annual basis. The two simple cycle turbines that exceeded the 36 percent threshold had annual electric sales of 39 and 45 percent and are located in Montana and New York, respectively. As noted earlier, the most efficient simple cycle turbine currently available is 44 percent efficient and would accommodate the operations at the Montana facility. The only existing simple cycle turbine that exceeded the maximum allowable percentage electric sales threshold of 44 percent, which is based on current simple cycle designs, sold an abnormally high amount of electricity in 2014. It is possible that this unit was operating under emergency conditions. As explained below, the incremental generation due to the emergency would not have counted against the percentage electric sales threshold.

We are capping the percentage electric sales threshold at 50 percent of potential electric output for multiple reasons. First, NGCC emission rates are relatively steady above 50 percent electric sales, so there is no reason that a NGCC unit with sales greater than this amount should not have to comply with the output-based standard for the base load subcategory. Second, the net design efficiency of the fast-start NGCC units intended for peaking and intermediate load applications is 49 percent. As described earlier, this technology can serve the same purpose as high-efficiency simple cycle turbines. If we were to set a cap any lower than 50 percent, it could create a disincentive for owners and operators to choose this promising new technology.

Finally, the EPA solicited comment on excluding electricity sold during system emergencies from counting towards the percentage electric sales threshold. After considering the comments, we have concluded that this exclusion is necessary to provide flexibility, maintain system reliability, and minimize overall costs to the sector. We disagree with commenters that suggested that the EPA's existing enforcement discretion would be a viable alternative. An enforcement discretion-based approach would not provide certainty to the regulated community, public, and regulatory authorities on the applicability of the emission standards, which is a primary reason why we are finalizing the broad applicability approach. Moreover, system emergencies are defined events, so commenters' fears that the exclusion will be subject to abuse are overstated. Therefore, electricity sold during hours of operation when a unit is called upon to operate due to a system emergency will not be counted toward the percentage electric sales threshold. However, electricity sold by units that are not called upon to operate due to a system emergency (*e.g.,* units already operating when the system emergency is declared) will be counted toward the percentage electric sales threshold.

In summary, the EPA is finalizing the percentage electric sales criterion as a threshold to distinguish between two natural gas-fired combustion turbine subcategories. Specifically, all units that have electric sales greater than their net LHV design efficiencies (as a percentage of potential electric output) are base load units. All units that have electric sales less than or equal to their net LHV design efficiencies are non-base load units. We are capping the percentage electric sales threshold at 50 percent of potential electric output. This sliding-scale approach will limit the operation of the least efficient units, provide flexibility for renewable energy growth, and incentivize the development of more efficient simple cycle units.

3. Fuel-Based Subcategories

As described in Section IX.A.3.d, we are finalizing a version of the broad applicability approach. Under the broad applicability approach, the EPA solicited comment on a subcategorization approach based in part on natural gas-use. We received few comments on this issue. One of the comments we did receive was that combustion turbines that burn fuels other than natural gas have higher CO_2 emissions due to the higher relative carbon content of alternate fuels. Besides hydrogen,[533] natural gas has the lowest CO_2 emission rate on a lb/MMBtu basis of any fossil fuel. Therefore, burning fuels other than natural gas will result in a higher CO_2 emission rate. We interpret this comment to mean that, if we were to subcategorize based on fuel use, turbines that burn non-natural gas fuels should receive a less stringent emission standard.

For the reasons described in the applicability section, we have decided to set emission standards for all combustion turbines capable of burning natural gas, regardless of the actual fuel burned, to avoid the practical problems that would have arisen under the proposed approach. However, as commenters explained, multi-fuel-fired combustion turbines cannot achieve the emission standards achieved by natural-gas fired turbines. For this reason, it would not be reasonable to require affected EGUs to comply with a standard based on the use of natural gas during periods when significant quantities of non-natural gas fuels are being burned. If we did not subcategorize, owners and operators would not be able to combust other fuels in their turbines, including process gas, blast furnace gas, and petroleum-based liquid wastes, which might otherwise be wasted. In addition, without the ability to burn back up fuels during natural gas curtailments, grid reliability could be jeopardized. Therefore, we are finalizing a separate fuel-based subcategory for multi-fuel-fired combustion turbines. To distinguish between this subcategory and the natural gas-fired subcategories, we are using the same threshold as proposed. Specifically, combustion turbines that burn ninety percent or less natural gas on a 12-operating-month rolling average basis will be included in this subcategory and subject to a separate emission standard, which is discussed in Section IX.D.3.d.

C. Identification of the Best System of Emission Reduction

This section summarizes the EPA's proposed BSER determinations for stationary combustion turbines, provides a summary of the comments we received, and explains our final BSER determinations for each of the three subcategories we are now finalizing. For natural gas-fired stationary combustion turbines operating as base load units, we proposed and are finalizing the use of NGCC technology as the BSER. For the other two subcategories of affected combustion turbines—non-base load natural gas-fired combustion turbines and multi-fuel-fired combustion turbines—we are finalizing the use of clean fuels as the BSER.

1. Proposed BSER

We considered three alternatives in evaluating the BSER for base load natural gas-fired combustion turbines: (1) Partial CCS, (2) high-efficiency simple cycle aeroderivative turbines, and (3) modern, efficient NGCC turbines. We rejected partial CCS as the BSER because we concluded that we did not have sufficient information to determine whether implementing CCS for combustion turbines was technically feasible. We rejected high-efficiency simple cycle aeroderivative turbines as the BSER because this standalone technology does not provide emission reductions and generally is more expensive than NGCC technology for base load applications. In contrast, NGCC is the most common type of new fossil fuel-fired EGU currently being planned and built for generating base load power. NGCC is technically feasible, and NGCC units are currently the lowest-cost, most efficient option for new base load fossil fuel-fired power generation. After considering the options, the EPA proposed to find that modern, efficient NGCC technology is the BSER for base load natural gas-fired combustion turbines.

For non-base load natural gas-fired units and multi-fuel-fired units, we did not propose a specific BSER or associated numeric emission standards, but instead solicited comment on these issues.

2. Comments on the Proposed BSER for Base Load Natural Gas-Fired Combustion Turbines

This section summarizes the differing comments submitted on the proposed BSER for base load natural gas-fired combustion turbines. Some commenters supported partial CCS as the BSER, others supported advanced NGCC

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[533] Hydrogen would only be considered a fossil fuel if it were derived for the purpose of creating useful heat from coal, oil, or natural gas.

designs as the BSER, and others supported the proposed BSER.

a. Partial CCS

Some commenters stated that our proposed BSER analysis for stationary combustion turbines was inconsistent with our proposed BSER analysis for coal-fired units. They stated that the EPA had determined that the use of CCS was feasible for coal-fired generation based on current CCS projects under development at coal-fired generating stations, but did not come to the same conclusion for combustion turbines. These commenters stated that CO_2 removal is just as technologically feasible and economically reasonable for a natural gas-fired EGU as for a coal-fired EGU. While some of these commenters wanted the EPA to reconsider CCS as the BSER for NGCC, many of these commenters were attempting to prove that if the agency did not choose CCS as the BSER for NGCC units, then the agency should not for coal-fired units either.

Some commenters referenced the Northeast Energy Association NGCC plant in Bellingham, MA, which operated from 1991–2005 with 85–95 percent carbon capture on a 320 MW unit for use in the food and beverage industry, that was referred to in the proposal. This plant captured 330 tons of CO_2 per day from a 40 MW slip stream and was decommissioned as a result of financial difficulties, including rising gas prices and discontinuation of tax credits. According to these commenters, this plant provided sufficient proof that CCS technology is adequately demonstrated for NGCC units. Additionally, these commenters referred to other NGCC plants that are planned or in development that will incorporate CCS. The plants mentioned were the Sumitomo Chemical Plant in Japan, the Peterhead CCS project in Scotland, and the GE-Sargas Plant in Texas. The Sumitomo Chemical Plant has a base load NGCC unit with CCS operating on an 8 MW slip-stream that captures about 150 tons of CO_2 per day for commercial use in the food and beverage industry. This carbon capture system has been operating since 1994. The Peterhead CCS project in Scotland is in the planning stages. It is a collaboration between Shell and SSE to provide 320 MW of electricity to its customers from a base load NGCC unit with 90 percent carbon capture. The CO_2 will be transported to the depleted Goldeneye reservoir in the ocean where it will be stored and continuously monitored. The GE-Sargas Plant in Texas is a planned joint venture that does not currently have a location selected, but is intended to be a base load NGCC unit with CCS used for EOR.

These commenters also referenced reports authored by DOE, NETL, the Clean Air Task Force (CATF), CCS Task Force, ICF Inc., and Global CCS Institute, suggesting that, because CCS technology for NGCC is included in these reports, it is adequately demonstrated. Some commenters referred to a DOE/NETL study that suggested that the cost of CCS for NGCC units would be more cost-effective than for coal-fired EGUs. One non-industry commenter emphasized that a technology does not have to be in use to be considered adequately demonstrated.

In addition, some commenters disagreed with the EPA's decision to treat combustion turbines differently than coal-fired units with respect to CCS on the basis that combustion turbines startup, shutdown, and cycle load more frequently than coal-fired units. According to these commenters, the operating characteristics of combustion turbines do fluctuate, but so do those of coal-fired units. Another commenter said that even if NGCC operations vary more than they do for coal-fired units, it is not an impediment to using CCS because combustion turbine operators could bypass the carbon capture system during startup and shutdown modes (which are typically shorter and less intensive efforts compared to the startup or shutdown of a coal facility) and then employ the carbon capture system when operating normally. One commenter stated that most future base load fossil fuel-fired generation will be NGCC and that not making CCS the BSER for NGCC would result in significant CO_2 emissions.

Other commenters supported the EPA's determination that CCS is not the BSER for combustion turbines. These commenters said that CCS is not adequately demonstrated for combustion turbines because none are currently operating, under construction, or in the advanced stages of development. They also noted that CCS would have to be demonstrated for the range of facilities included in the regulated source category, which they alleged includes both simple cycle and NGCC units. They specifically noted that the Bellingham, MA demonstration facility was not a full-scale commercial NGCC power plant operating with CCS.

These commenters agreed with the EPA that CCS does not match well with the operating flexibilities of NGCC and simple cycle units. They agreed with the EPA that frequent cycling restricts the efficacy of CCS on these units, a problem which would only get worse as more renewable energy sources are integrated into the grid. These commenters added that NGCC units operate differently than coal-fired units because the former start, stop, and cycle frequently, whereas the latter tend to operate at relatively steady loads and do not start and stop frequently. They stated that even if technical barriers could be overcome, the application of CCS to combustion turbines would be more costly (compared to the application of CCS to coal-fired units) on a dollars-per-ton basis. In addition, these commenters said that other industries' experience with CCS could not be transferred to NGCC units due to differences in flue gas CO_2 concentration.

Some commenters stated that CAA section 111(a) requires the EPA to account not only for the cost of achieving emission reductions, but also for impacts on energy requirements and the environment. The commenters cited to *Sierra Club* v. Costle, where the D.C. Circuit observed that the EPA ''must exercise its discretion to choose an achievable emission level which represents the best balance of economic, environmental, and energy considerations.'' [534] The commenters stated that requiring CCS on combustion turbines would adversely affect the nation's energy needs and the environment because imposing CCS on combustion turbines would invariably delay the emission reductions that can be obtained from new NGCC projects that displace load from older, less efficient generating technologies. In addition, the commenters stated that, because combustion turbines are projected to provide a significant share of new power generation, the EPA should recognize that requiring CCS on these units would have a disproportionally higher impact on electricity prices when compared to the projected number of new coal-fired projects. These commenters concluded that the EPA could not determine that CCS is the BSER for combustion turbines without producing severe and unacceptable consequences for the availability of affordable electricity in the U.S.

b. NGCC Turbines

Some commenters stated that the proposed BSER analysis should have reflected the emission rates achieved by the latest designs deployed at advanced, state-of-the-art NGCC installations. These commenters stated that advanced NGCC technologies are the best system

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[534] *Sierra Club* v. *Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981).

for reducing CO_2 emissions with no negative environmental impacts and no negative economic impacts on rate payers. They stated that advanced NGCC technologies are capable of achieving emission rates that are 8 percent lower than conventional NGCC facilities. They also said that the majority of existing sources that do not deploy these advanced technologies are currently able to meet the standard and that the proposal failed to explain why these lower-emitting advanced technologies that are more than adequately demonstrated were not selected as the BSER.

c. Simple Cycle Turbines

Many commenters opposed the EPA's proposal to set emission standards for combustion turbines based on their function rather than based on their design. These commenters stated that the EPA's determination that NGCC technology is the BSER for base load natural gas-fired combustion turbines would apply equally to simple cycle turbines if they sell electricity in excess of the percentage electric sales threshold. They pointed to the word ''achievable'' in CAA section 111(a)(1) and stated that applying an emission standard based on NGCC technology to simple cycle units was legally indefensible because simple cycle units cannot achieve emission rates as low as NGCC units. In contrast, many other commenters agreed with the EPA's basic approach and stated that NGCC technology should be the BSER for base-load functions, while simple cycle technology should be the BSER for peak-load functions.

3. Comments on Non-Base Load and Multi-Fuel-Fired Combustion Turbines

Multiple commenters suggested that high efficiency simple cycle or fast-start NGCC technologies should be the BSER for non-base natural gas-fired load units. They explained that high efficiency simple cycle units and fast-start NGCC units are actually more efficient when serving non-base load demand than NGCC units that are designed strictly for base load operation. Some commenters also suggested that we should subcategorize multi-fuel-fired combustion turbines, but did not provide any specific technologies that should be considered in the BSER analysis.

4. Identification of the BSER

After our evaluation of the comments and additional analysis, we identified the BSER for each subcategory of combustion turbine that we are finalizing: base load natural gas-fired units, non-base load natural gas-fired units, and multi-fuel-fired units.

a. Base Load Natural Gas-Fired Units

As described in the proposal, we evaluated CCS, NGCC, and high-efficiency simple cycle combustion turbines as the potential BSER for this subcategory. We selected NGCC as the BSER because it met all the BSER criteria. This section describes our response to issues raised by commenters and our rationale for maintaining that NGCC is the BSER for base load natural gas-fried combustion turbines.

(1) Partial CCS

Some commenters stated that CCS could be applied equally to both coal-fired and natural gas-fired EGUs. To support this conclusion, the commenters pointed to a retired NGCC-with-CCS demonstration project, as well as a few overseas projects and projects in the early stages of development. While we have concluded that these commenters made strong arguments that the technical issues we raised at proposal could in many instances be overcome, we have concluded that there is not sufficient information at this time for us to determine that CCS is adequately demonstrated for all base load natural-gas fired combustion turbines.

While the commenters make a strong case that the existing and planned NGCC-with-CCS projects demonstrate the feasibility of CCS for NGCC units operating at steady state conditions, many NGCC units do not operate this way. For example, the Bellingham, MA and Sumitomo NGCC units cited by the commenters operated at steady load conditions with a limited number of starts and stops, similar to the operation of coal-fired boilers.[535] In contrast, our base load natural gas-fired combustion turbine subcategory includes not only true base load units, but also some intermediate units that cycle more frequently, including fast-start NGCC units that sell more than 50 percent of their potential output to the grid. Fast-start NGCC units are designed to be able to start and stop multiple times in a single day and can ramp to full load in less than an hour. In contrast, coal-fired EGUs take multiple hours to start and ramp relatively slowly. These differences are important because we are not aware of any pilot-scale CCS projects that have demonstrated how fast and frequent starts, stops, and cycling will impact the efficiency and reliability of CCS. Furthermore, for those periods in which a NGCC unit is operating infrequently, the CCS system might not have sufficient time to startup. During these periods, no CO_2 control would occur. Thus, if the NGCC unit is intended to operate for relatively short intervals for at least a portion of the year, the owner or operator could have to oversize the CCS to increase control during periods of steady-state operation to make up for those periods when no control is achieved by the CCS, leading to increased costs and energy penalties. While we are optimistic that these hurdles are surmountable, it is simply premature at this point to make a finding that CCS is technically feasible for the universe of combustion turbines that are covered by this rule.

Notably, the Department of Energy has not yet funded a CCS demonstration project for a NGCC unit, and no NGCC-with-CCS demonstration projects are currently operational or being constructed in the U.S. In contrast, multiple CCS demonstration projects for coal-fired units are in various stages of development throughout the U.S., and a full-capture system is in operation at the Boundary Dam facility in Canada. See Sections V.E and D above.

One commenter suggested that not having CCS as the BSER for combustion turbines would ultimately halt the development of CCS in the U.S. We disagree. A number of coal-fired power plants are currently being built with CSS, while some existing plants are considering CCS retrofits. Moreover, the NSPS sets the minimum level of control for new sources. We expect that state air agencies and other air permitting authorities will evaluate CCS when permitting new NGCC power plants, taking into consideration case-specific parameters, like operating characteristics, to determine whether CCS could be BACT or LAER in specific instances. While the NGCC-with-CCS units that currently are in the planning stages do not provide us with enough assurance to determine that CCS is adequately demonstrated for combustion turbines, it is our expectation that these units and others to come will provide additional information for both permitting reviews and the next NSPS review in eight years.

(2) NGCC Turbines

Regarding the advanced NGCC technologies advocated by several commenters, the EPA has concluded

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[535] As explained in Section V.J above, a new fossil fuel-fired steam generating EGU would, most likely, be built to serve base load power demand exclusively and would not be expected to routinely startup, shut down, or ramp its capacity factor in order to follow load demand. Thus, planned start-up and shutdown events would only be expected to occur a few times during the course of a 12-operating-month compliance period.

that the term ''advanced'' simply refers to incremental improvements to traditional NGCC designs, not a new and unique technology. These incremental improvements include higher firing temperatures in the turbine engine, increasing the number of steam pressures, and adding a reheat cycle to the steam cycle. The emission rates achieved by these so-called ''advanced'' technologies were included within the data set of newer NGCC designs that we used to establish the final emission standards. In addition, our review of the operating data for NGCC power blocks installed since 2000 indicates that a unit's mode of operation in response to system demand (*e.g.,* capacity factor) affects efficiencies achieved to the extent that we cannot evaluate the impact of particular subcomponents used within the power block. As a result, a conventional NGCC power block located in a region of the country where system demand requires the power block to run continuously at a steady high load can achieve higher efficiencies than an ''advanced'' NGCC power block located in a region where system demand requires the power block to cycle on and off to match system demand. For this reason, our data set included a large population of technologies and load conditions to ensure that new NGCC power blocks can achieve the final emission standards in all regions of the country.

As we explained in the proposal, NGCC technology meets all of the BSER criteria. For base load functions, NGCC units are technically feasible, cost-effective (indeed, less expensive than simple cycle combustion turbines), and have no adverse energy or environmental impacts. Moreover, NGCC units reduce emissions because they have a lower CO_2 emission rate than simple cycle units. Finally, selecting NGCC as the BSER will promote the development of new technology, such as the incremental improvements advocated by the commenters, which will further reduce emissions in the future.

Some commenters suggested that the costs and efficiency impacts of startup and shutdown events are higher for NGCC units than for simple cycle units. Consequently, we refined the LCOE costing approach used at proposal by adding these additional costs and efficiency impacts to our cost comparison. Even accounting for these new costs and impacts, we found that NGCC technology results in a lower cost of electricity than simple cycle technology when a unit's electric sales exceed approximately one-third of its potential electric output. The final percentage electric sales criterion for the base load natural gas-fired combustion turbine subcategory is based on the sliding scale. This means that the dividing line between the base load subcategory and the non-base load subcategory will change depending on a unit's nameplate design efficiency. For a conventional simple cycle turbine, the base load subcategory will begin at around 33 percent electric sales, while for a newer fast-start NGCC turbine, the base load subcategory will begin at approximately 50 percent electric sales. Anywhere within this range, our cost calculations have shown that NGCC technology is more cost-effective than simple cycle technology. Therefore, we are finalizing our determination that modern, efficient NGCC technology is the BSER for base load natural-gas fired combustion turbines.

(3) Simple Cycle Turbines

Many commenters mistakenly thought that the EPA proposed to require some simple cycle combustion turbines to meet an emission standard of 1,000 lb CO_2/MWh-g, a level that they assert is unachievable. On the contrary, the EPA is not finding that NGCC technology and a corresponding emission standard of 1,000 lb CO_2/MWh-g is the BSER for simple cycle turbines. Instead, the EPA is finding that NGCC technology is the BSER for base load turbine applications. This means that if an owner or operator wants to sell more electricity to the grid than the amount derived from a unit's nameplate design efficiency calculated as a percentage of potential electric output, then the owner or operator should install a NGCC unit. If the owner or operator elects to install a simple cycle turbine instead, then the practical effect of our final standards will be to limit the electric sales of that unit so that it serves primarily peak demand, not to subject it to an unachievable emission standard.

b. Non-base Load Natural Gas-Fired Load Units

To identify the BSER for non-base load natural gas-fired units, we evaluated a range of technologies, including partial CCS, high-efficiency NGCC technology designed for base load applications, fast-start NGCC, high-efficiency simple cycle units (*i.e.,* aeroderivative turbines), and clean fuels. For each of these technologies, we considered technical feasibility, costs, energy and non-air quality impacts, potential for emission reductions, and ability to promote technology.

While CCS would result in emission reductions and promote the development of new technology, we concluded that CCS does not meet the BSER criteria because the low capacity factors and irregular operating patterns (*e.g.,* frequent starting and stopping and operating at part load) of non-base load units make the technical challenges associated with CCS even greater than those associated with base load units. In addition, because the CCS system would remain idle for much of the time while these units are not running, CCS would be less cost-effective for these units than for base load units.

We have also concluded that the high-efficiency NGCC units designed for base load applications do not meet any of the BSER criteria for non-base load units. First, non-base load units need to be able to start and stop quickly, and NGCC units designed for base load applications require relatively long startup and shutdown periods. Therefore, conventional NGCC designs are not technically feasible for the non-base load subcategory. Also, non-base load units operate less than 10 percent of the time on average. As a result, conventional NGCC units designed for base load applications, which have relatively high capital costs, will not be cost-effective if operated as non-base load units. In addition, it is not clear that a conventional NGCC unit will lead to emission reductions if used for non-base load applications. As some commenters noted, conventional NGCC units have relatively high startup and shutdown emissions and poor part-load efficiency, so emissions may actually be higher compared with simple cycle technologies that have lower overall design efficiencies but better cycling efficiencies. Finally, requiring conventional NGCC units as the BSER for non-base load combustion turbines would not promote technology because these units would not be fulfilling their intended role. In fact, it could hamper the development of technologies with lower design efficiencies that are specifically designed to operate efficiently as non-base load units (*i.e.,* high-efficiency simple cycle and fast-start NGCC units). For all these reasons, we have concluded that conventional NGCC units designed for base load applications are not the BSER for non-base load natural gas-fired units.

Compared to conventional NGCC technology, fast-start NGCC units have lower design efficiencies, but are able to start and ramp to full load more quickly. Therefore, it is possible that requiring fast-start NGCC as the BSER for non-base load units would result in emission reductions and further promote the development of fast-start NGCC technology, which is relatively new and advanced. However, because the majority of non-base load combustion turbines operate less than 10 percent of the time, it would be cost-prohibitive to require fast-start NGCC, which have relatively high capital costs compared to simple cycle turbines, as the BSER for all non-base load applications. Also, as we explained above in Section IX.B.2, we do not have sufficient emissions data for fast-start NGCC units operating over the full range of non-base load conditions (*e.g.,* peaking, cycling, etc.), so we would not be able to establish a reasonable emission standard.

High-efficiency simple cycle turbines are primarily used for peaking applications. High-efficiency simple cycle turbines often employ aeroderivative designs because they are more efficient at a given size and are able to startup and ramp to full load more quickly than industrial frame designs. Requiring high-efficiency simple cycle turbines as the BSER could result in some emission reductions compared with conventional simple cycle turbines. It would also promote technology development by incentivizing manufacturers to increase the efficiency of their simple cycle turbine models. However, aeroderivative designs have higher initial costs that must be weighed against the specific peak-load profiles anticipated for a particular new non-base load unit. Many utility companies have elected to install the heavier industrial frame turbines because the ramping capabilities of aeroderivative turbines are not required for their system demand profiles (*i.e.,* the speed and durations of daily changes in electricity demand), and the fuel savings do not justify the higher initial costs. We currently do not have precise enough costing information to compare the cost-effectiveness of aeroderivative turbines and industrial frame turbines for all non-base load applications. Determining cost-effectiveness is further complicated because the efficiencies of the available aeroderivative and industrial frame technologies significantly overlap. For example, the efficiencies of aeroderivative turbines range from 32 to 39 percent, while the efficiencies of industrial frame turbines range from 30 to 36 percent. Based on these cost uncertainties, we cannot conclude that high-efficiency simple cycle turbines are the BSER for natural gas-fired non-base load applications at this time.

The final option that we considered for the BSER was clean fuels, specifically natural gas with a small allowance for distillate oil. The use of clean fuels is technically feasible for non-base load units. Based on available EIA data,[536] natural gas comprises more than 96 percent of total heat input for simple cycle combustion turbines. In addition, natural gas is frequently the lowest cost fossil fuel used in combustion turbines, so it is cost-effective. Clean fuels will also result in some emission reductions by limiting the use of fuels with higher carbon content, such as residual oil. Finally, the use of clean fuels will not have any significant energy or non-air quality impacts. Based on these factors, the EPA has determined that the BSER for non-base load natural gas-fired units is the use of clean fuels, specifically natural gas with a small allowance for distillate oil. Natural gas has approximately thirty percent lower CO_2 emissions per million Btu than other fossil fuels commonly used by utility sector non-base load units.

c. Multi-Fuel-Fired Units

To identify the BSER for multi-fuel-fired units, we again evaluated CCS, NGCC technology, high-efficiency simple cycle units (*i.e.,* aeroderivative turbines), and clean fuels. For each of these technologies we considered technical feasibility, costs, energy and non-air quality impacts, emission reductions, and technology promotion. For many of the same reasons we provided above in our discussion of the BSER for non-base load natural gas-fired combustion turbines, only clean fuels meets the BSER criteria for multi-fuel-fired units.

While CCS would result in emission reductions and the promotion of technology, we concluded that CCS does not meet the BSER criteria because multi-fuel-fired units tend to start, stop, and operate at part load frequently. Also, there are impurities and contaminants in some alternate fuels which make the technical challenges of applying CCS to multi-fuel-fired units greater than for natural gas-fired units.

In regards to NGCC technology, we have concluded that it is technically feasible, would result in emission reductions, is cost-effective, and would promote the development of technology. However, a BSER determination based on the use of NGCC technology could pose challenges for facilities operating in remote locations and certain industrial facilities. In remote locations, the construction of a NGCC facility is often not practical because it requires larger capital investments and significant staffing for construction and operation. In contrast, simple cycle turbines are cheaper and can be operated with minimal staffing. Also, many industrial facilities do not have the space available to build a HRSG and the associated cooling tower. Therefore, requiring NGCC as the BSER could have unforeseen energy impacts at these types of facilities. Moreover, these same kinds of facilities also burn by-product fuels. Faced with a decision to install an NGCC unit, these facilities might seek alternative energy options, which could lead to increased flaring or venting of by-product fuels because they are no longer being burned onsite for energy recovery. Therefore, in light of these potential energy and non-air quality impacts, we have concluded that NGCC technology is not the BSER for multi-fuel-fired combustion turbines.

Similarly, while high-efficiency simple cycle turbines would result in emission reductions and promote the advancement of this technology, we are not confident that high-efficiency simple cycle units are technically feasible or cost-effective for this subcategory. Aeroderivative turbines are not as flexible with regards to what fuels that can be burned. Because by-product fuels vary in composition, it is not clear that all by-products fuels could be burned in a high-efficiency simple cycle turbine. In addition, even if a by-product fuel could be burned in an aeroderivative turbine, we do not have information on the potential for increased maintenance costs, so we cannot determine whether using high-efficiency simple cycle turbines would be cost-effective.

The final option that we considered for the BSER was clean fuels. The use of clean fuels is technically feasible and cost-effective. The use of clean fuels also provides an environmentally beneficial alternative to the flaring or venting of by-product fuels and limits the use of dirtier fuels with higher CO_2 emission rates, such as residual oils. Clean fuels also promote technology development by allowing manufacturers to develop new combustion turbine designs that are capable of burning by-product fuels that currently cannot be burned in combustion turbines. Finally, the use of clean fuels does not have any significant energy or non-air quality impacts. Based on these factors, the EPA has determined that the BSER for multi-fuel-fired combustion turbines is the use of clean fuels.

D. Achievability of the Final Standards

We are finalizing emission standards for three subcategories of combustion turbines. Specifically, units that sell electricity in excess of a threshold based on their design efficiency and that burn more than 90 percent natural gas (*i.e.,* base load natural gas-fired units) will be

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[536] *http://www.eia.gov/electricity/data/eia923/.*

subject to an output- based standard. The output-based standard is based on the performance of existing NGCC units and takes into account a range of operating conditions, future degradation, etc. Units not meeting either the percentage electric sales or natural gas-use criteria (*i.e.,* non-base load natural gas-fired and multi-fuel units, respectively) will be subject to an input-based standard based on the use of clean fuels. This section summarizes what emission standards we proposed and related issues we solicited comment on, describes the comments we received regarding the proposed emission standards and our responses to those comments, and provides our rationale for the final emission standards.

1. Proposed Standards

For large newly constructed, modified, and reconstructed stationary combustion turbines (base load rating greater than 850 MMBtu/h), we proposed an emission standard of 1,000 lb CO_2/MWh-g. For small stationary combustion turbines (base load rating of 850 MMBtu/h or less), we proposed an emission standard of 1,100 lb CO_2/MWh-g. We also solicited comment on a range of 950–1,100 lb CO_2/MWh-g for large stationary combustion turbines and a range of 1,000–1,200 lb CO_2/MWh-g for small stationary combustion turbines.

In addition, we solicited comment on increasing the size distinction between large and small stationary combustion turbines to 900 MMBtu/h to account for larger aeroderivative designs; increasing the size distinction to 1,000 MMBtu/h to account for future incremental increases in base load ratings; increasing the size distinction to between 1,300 to 1,800 MMBtu/h; and eliminating the size subcategories altogether. To account for potential reduced efficiencies when units are not operating at base load, we also solicited comment on whether a separate, less stringent standard should be established for non-base load combustion turbines.

2. Comments

As described previously, we are not finalizing the size-based subcategories that we proposed and instead are finalizing emission standards for sales- and fuel-based subcategories. Specifically, we are finalizing emission standards for three subcategories of stationary combustion turbines: base load natural-gas fired units, non-base load natural gas-fired units and multi-fuel-fired units. The relevant comments concerning the emission standards for the first two subcategories are discussed below. Any comments we received supporting tiered emission standards are included in the discussion of non-base load natural gas-fired units. We did not receive comments on an appropriate emission standard for multi-fuel-fired units.

a. Emission standards for Base Load Natural Gas-Fired Units

Many commenters stated that the proposed emission standards did not properly take into account the losses in efficiency that occur due to long-term degradation over multiple decades, operation at non-base load conditions (load cycling, frequent startups and shutdowns, and part-load operations), site-specific factors such as ambient conditions and cooling technology, and secondary fuel use (*e.g.,* distillate oil). These commenters stated that the EPA should conduct a more comprehensive analysis that addresses worst-case conditions for each of these factors. They also stated that all of the units included in the analysis supporting the proposal were relatively new and therefore have experienced limited degradation. The commenters stated that, while some degradation in efficiency can be recovered during periodic maintenance outages, it is not always possible or feasible to repair a degraded component immediately because repairs often involve extended outages that must be scheduled well in advance. They stated that a new unit that initially could meet the standard at base load conditions can experience increasing heat rates with age even when adhering to the manufacturer's recommended maintenance program.

Some commenters stated that the proposed standards were derived by looking at emissions data from years with historically low natural gas prices. They surmised that the NGCC units were taking advantage of these prices by running at historically high capacity factors and concluded that the efficiencies and CO_2 emission rates underlying the proposed standards were not representative of periods with higher natural gas prices. Other commenters said that many NGCC units are increasingly required to cycle and operate at lower capacities (compared to the proposal's baseline) to accommodate hourly variations in intermittent renewable generation. They anticipated that this type of generation will increase, requiring NGCC units to start, stop, and operate at part load more frequently than in the past, increasing CO_2 emissions.

Some commenters indicated that, during startup, combustion turbines must be operated at low load for extended periods to gradually warm up the HRSG to minimize thermal stresses on pressure vessels and boiler tubes. During these startup periods, significant CO_2 emissions occur, but steam production is not sufficient for the steam turbine generator to produce electricity. They also stated that a similar situation occurs during shutdown when the steam cycle does not generate electricity, but the combustion turbine is still combusting fuel as it proceeds through the shutdown process. These commenters recommended that the EPA could address these issues by creating a subcategory for NGCC units that cycle and operate at intermediate load.

Many commenters said that site-specific factors can often preclude operators from achieving design efficiencies based on ISO conditions. These factors include high elevations, high ambient temperatures, and cooling system constraints. They stated that local water temperatures can impact condenser operating pressure and heat rates. They also said that areas with limited water resources could require systems that rely on air-cooled condensers, which cannot achieve thermal efficiencies comparable to water-cooled plants. These commenters stated that the final rule should include provisions for addressing site-specific constraints that preclude individual affected EGUs from achieving the emissions rates achieved on average by other sources.

Some commenters stated that the proposed standards for modified and reconstructed combustion turbines would foreclose future opportunities for operators to undertake projects to restore the performance of both degraded units subject to the NSPS and existing, pre-NSPS units. They said that it is not possible to bring older combustion turbines (built prior to the year 2000) up to the efficiency levels of modern units because many newer technological options that deploy higher temperatures are not available for pre-2000 combustion turbines.

Commenters from the power sector generally supported increasing the standards to 1,100 lb CO_2/MWh-g and 1,200 lb CO_2/MWh-g for the newly constructed large and small turbines, respectively. They also advocated finalizing standards for modified and reconstructed standards that are 10 percent higher than the final standards for new sources because combustion turbines constructed prior to 2000 were not included in the EPA's analysis.

Conversely, some commenters stated that the proposed standards for combustion turbines do not reflect the emission rates that are achievable by modern, efficient NGCC power blocks. These commenters stated that the appropriate standard, consistent with Congressional objectives under CAA section 111, should be 800 lb CO_2/MWh-g based on the performance of the lowest emitters in the CAMD database. Some commenters stated that a standard of 850 lb CO_2/MWh-g reflects BSER for high-capacity factor units because half of the NGCC units in the CAMD database are achieving this level of emissions. One commenter from the power sector who operates NGCC power plants stated that the final standard for new large combustion turbines should be 925 lb CO_2/MWh-g. Another commenter also supported an emission standard of 925 lb CO_2/MWh-g, which is consistent with recent BACT determinations in the state of New York. Several other commenters stated that a reasonable standard for new large combustion turbines should be 950 lb CO_2/MWh-g and that the final standard for new small combustion turbines should be 1,000 lb CO_2/MWh-g. Numerous commenters stated that the final standards for new sources should not exceed 1,000 lb CO_2/MWh-g for either large or small combustion turbines. Other commenters stated that, because the standards were developed based on emission rates that are being achieved by the majority of existing units, the final standards should be the same for new, modified, and reconstructed units.

b. Emission Standards for Non-Base Load Natural Gas-Fired Units and Multi-Fuel-Fired Units

Many commenters stated that the EPA cannot finalize ''no emission standard'' for non-base load units, which the EPA solicited comment on in the broad applicability approach. They argued that this approach was not consistent with the definition of ''standard of performance'' in CAA section 111(a)(1), which requires there to be an ''emission limitation'' that reflects a ''system of emission reduction.'' Some commenters recommended that non-base load units should be subject to work practice standards, such as operating safely with good air pollution control practices, including CO_2 monitoring and reporting requirements. Other commenters pointed to recent PSD permits that include tiered emission limits for the different roles served by combustion turbines. They cited BACT limits from 1,328 to 1,450 lb CO_2/MWh-g for peaking units. One commenter supported tiered limits consistent with recent BACT determinations in the state of New York, which include limits for simple cycle combustion turbines of 1,450 lb CO_2/MWh-g. An air quality regulator from a state with rapidly increasing renewable generation supported a limit of 825 lb CO_2/MWh-g for all base load NGCC units; 1,000 lb CO_2/MWh-g for large intermediate load NGCC units; 1,100 lb CO_2/MWh-g for small intermediate load NGCC units. This commenter also recommended that the EPA set a numerical limit specifically for peaking units after the completion of a peaking unit-specific BSER analysis. Several commenters supported tiered standards based on capacity factor. They proposed 825 lb CO_2/MWh-g for base load units (those operating over 4,000 hours annually), 875 lb CO_2/MWh-g for intermediate and load-following units (those operating between 1,200 and 4,000 hours annually), and 1,100 lb CO_2/MWh-g for peaking units (those operating less than 1,200 hours per year).

3. Final Standards

a. Newly Constructed Base Load Natural Gas-Fired Units

In evaluating the achievability of the base load natural gas-fired emission standard, we focused on three types of data. Specifically, we looked at existing NGCC emission rates, recent PSD permit limits for CO_2 emissions, and NGCC design efficiency data and specifications. Based on this analysis, we have concluded that an emission rate of 1,000 lb CO_2/MWh-g is appropriate for all base load natural gas-fired combustion turbines, regardless of size.

Since the standards were proposed, the EPA has expanded the NGCC emission rate analysis that supported the proposed emission standards to include emissions information for NGCC units that commenced operation in 2011, 2012, and 2013, and updated the emissions data to include emissions through 2014. In our analysis, we evaluated 345 NGCC units with online dates ranging from 2000 to 2013. The analysis included emissions data from 2007 to 2014 as submitted to the EPA's CAMD. The average maximum 12-operating-month CO_2 emission rate for all NGCC units was 897 lb CO_2/MWh-g, with individual unit maximums ranging from 751 to 1,334 lb CO_2/MWh-g.

Consistent with our proposed size-based subcategories, we also reviewed the emissions data for small and large NGCC units separately. For small units, we evaluated emissions data from 17 NGCC units with heat input ratings of 850 MMBtu/h or less. These units had an average maximum 12-operating-month CO_2 emission rate of 953 lb/MWh-g. Individual unit maximum emission rates ranged from 898 to 1,175 lb CO_2/MWh-g. Two of the units had a maximum emissions rate equal to or greater than 1,000 lb CO_2/MWh-g.[537] However, one of the units with a maximum emission rate above 1,000 lb CO_2/MWh-g was only selling approximately 20 percent of its potential electric output (significantly below the design-specific percentage electric sales threshold) when the emission rate occurred. If this unit were a new unit, the applicable emission standard would be the heat input-based clean fuels standard, and the unit would not be out of compliance. Therefore, 16 of the 17 existing small NGCC units have demonstrated that an emission rate of 1,000 lb CO_2/MWh-g is achievable. In addition, the six newest units, which commenced construction between 2007 and 2012, all have maximum 12-operating-month emission rates of less than 950 lb CO_2/MWh-g. While these units might not be old enough to have experienced degradation, their maximum emission rates demonstrate that the final standard of 1,000 lb CO_2/MWh-g includes a significant compliance margin for any future degradation.

For large units, the average maximum 12-operating-month emission rate was 895 lb CO_2/MWh-g, with individual unit maximum emission rates ranging from 751 to 1,334 lb CO_2/MWh-g. Twenty-three of the 328 large NGCC units had maximum 12-operating-month emission rates greater than 1,000 lb CO_2/MWh-g. While we do not have precise design efficiency information for each of these units, and thus cannot calculate the precise percentage electric sales threshold to which each unit would be subject, it appears that all of the emission rates in excess of 1,000 lb CO_2/MWh-g occurred during periods when electric sales were low and would be below the threshold. Thus, if these units were new units, they would only have to comply with the heat input-based clean fuels standard. Therefore, essentially all existing NGCC units would have been in compliance with the final emission standard. We note also that there are 51 new NGCC units that have started operation since 2010, and the average maximum 12-operating-month emission rate for these units is 833 lb CO_2/MWh-g. Therefore, the final emission standard includes a very significant compliance margin to account for any potential future degradation of large units.

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[537] For emission standards of 1,000 lb CO_2/MWh-g and above, the emission standard uses three significant figures. See Section X.D.

To evaluate degradation further, the EPA reviewed the emission rate information for the 55 oldest NGCC units in our data set (*i.e.,* units that came online in 2000 and 2001). According to the commenters, we should expect to see degradation when reviewing the annual emissions data for these turbines because they are 14 to 15 years old. However, we did not see any sign of degradation. The CO_2 rates for these turbines have little standard deviation between 2007 and 2014. In addition, there were many instances where the CO_2 emission rate of a unit actually decreased with age. This indicates that the efficiency of the unit is increasing, possibly as a result of good operating and maintenance procedures or upgrades to equipment that improved efficiency beyond the original design. Based on these findings, we have concluded that our analysis adequately accounts for potential degradation.

We also evaluated the impact of elevation, ambient temperature, cooling type, and operating conditions (startups, shutdowns, and average run time per start) because commenters indicated that these could affect a unit's ability to achieve the standard. We saw little correlation between elevation or ambient temperature and emission rate. In addition, any correlation was relatively small and would have an insignificant impact on the ability of a unit to achieve the final standard. We identified 32 large NGCC units with dry cooling towers. The average maximum 12-operating-month emission rate for this group of units was 875 lb CO_2/MWh. This rate was actually lower than the average rate for the large NGCC group as a whole. Based on these findings, we have concluded that the final emission standard will not limit the use of dry cooling technologies. Finally, the EPA evaluated the impact of run time per start, average duty cycle, and number of starts on emission rates. While these factors do influence emission rates, the non-base load natural gas-fired subcategory inherently addresses efficiency issues related to operating conditions.

In addition to evaluating existing NGCC emissions data, the EPA reviewed the CO_2 emission limits included in PSD preconstruction permits issued since January 1, 2011. We evaluated all permit limits over an annual period. In total, we identified 31 major source PSD permits with 39 discrete limits on CO_2 emissions. Eight of the limits were expressed in terms of lb/h or tons per year, so we did not include them in the analysis. In addition, one CHP unit that generates electricity and supplies steam to a chemical plant was in the data set. This facility had a permit limit of 1,362 lb CO_2/MWh based only on gross electrical output and does not account for useful thermal output. Therefore, we did not include it in the analysis either. Finally, we excluded two permits that did not clearly specify if the output-based standard was on a gross or net basis.

The remaining 28 permit limits were expressed in lb CO_2/MWh or a heat rate basis that could be converted to lb CO_2/MWh. Eight permit limits were based on net output, ranging from 774–936 lb CO_2/MWh-n. The lowest emission limit was for a hybrid power plant with a solar component that could contribute up to 50 MW. Twenty permit limits were based on gross output, ranging from 833–1,100 lb CO_2/MWh-g. Of these 28 permit limits, the only limit in excess of our final emission standard of 1,000 lb CO_2/MWh-g is for a relatively small NGCC unit (base load rating of 366 MMBtu/h) that commenced construction prior to the proposal and thus will not be subject to the requirements of this final rule.

Each of the permit limits discussed above that is 1,000 lb CO_2/MWh or less includes all periods of operation, including startup, shutdown, and malfunction events. In addition, each permit limit was set after back up and additional fuel use were taken into consideration. While some permits restrict fuel use to only natural gas, others allow limited usage (duration and type) of back up and other fuels. For example, the Pioneer Valley Energy Center has unrestricted use of natural gas, but can burn ultra-low sulfur diesel (ULSD) for up to 1,440 hours per 12-month period. This permit requires the unit to comply with a limit of 895 lb CO_2/MWh-n even when burning up to 16 percent distillate oil. Each permit limit takes into account the mode of operation for the combustion turbine. For example, the permit for the Lower Colorado River Authority's Ferguson plant evaluated emission limits for the plant at 50, 75, and 100 percent gross load. The emission limit of 918 lb CO_2/MWh-n accounts for the unit's expected operation at 50 percent gross load. For NGCC units with duct burners on their HRSGs, the permit limits account for the hours of operation with duct burners firing. Finally, most of these permits include compliance margins to account for efficiency losses due to degradation and other factors (*e.g.,* actual operating parameters, site-specific design considerations, and the use of back up fuel). In total, these compliance margins result in a 10 to 13 percent increase in the permitted CO_2 emission limits, yet all of the limits except one were still below 1,000 lb CO_2/MWh-g.

Finally, we also reviewed NGCC design efficiency data and specifications submitted to *Gas Turbine World.* Specifically, we reviewed the reported efficiency data for 88 different 60 Hz NGCC units manufactured by Alstom, GE Energy Aeroderivative and Heavy Duty, Mitsubishi Heavy Industries, Pratt & Whitney, Rolls-Royce, and Siemens Energy. The designs ranged in model year from 1977 to 2011, capacities ranged from 31 to 1,026 MW, and base load ratings ranged from 236 to 3,551 MMBtu/h. The average reported design emission rate for these units was 834 lb CO_2/MWh-n and ranged from 725 to 941 lb CO_2/MWh-n. Therefore, our optional standard of 1,030 lb CO_2/MWh-n would allow for an average compliance margin of 24 percent, with a range from 10 to 42 percent, over the design rate. Ninety-five percent of designs would have a compliance margin of 13 percent or more, the top end of the range of compliance margins determined to be appropriate in the PSD permits we reviewed.

Because some commenters were concerned that smaller NGCC units will not be able to achieve the emission standard, we specifically considered the design rates for smaller units. For the 52 small units (base load rating of 850 MMBtu/h or less), the average design emission rate was 865 lb CO_2/MWh and ranged from 796 to 941 lb CO_2/MWh-n. Therefore, our optional standard of 1,030 lb CO_2/MWh-n would allow for an average compliance margin of 19 percent, with a range of 10 to 29 percent, over the design rate. Ninety-five percent of small NGCC designs would have a compliance margin of 13 percent or more.

We further refined our analysis by only considering the most efficient design for a given combustion turbine engine. For example, GE Energy Aeroderivative offers four design options for its LM2500 model-type, all with a rating of approximately 45 MW. The design emission rates for these various options range from 827 to 914 lb CO_2/MWh-n. When only the most efficient models for a particular combustion turbine engine design are considered, all NGCC models have over a 13 percent compliance margin. In other words, developers of new base load natural gas-fired combustion turbines concerned about the achievability of the final standard have multiple more efficient options offered by the same manufacturer. Therefore, we have concluded that the final emission standard allows sufficient flexibility for end users to select an

NGCC design appropriate for their specific requirements.

After considering these three sources of information—actual NGCC emission rate data, PSD permit limits for NGCC facilities, and NGCC design information—we have concluded that a standard of 1,000 lb CO_2/MWh is both achievable and appropriate for newly constructed base load natural gas-fired combustion turbines. While we anticipate that the large majority of new NGCC units will operate well below this emission rate, this standard provides flexibility for developers to take into account site-specific conditions (*e.g.,* ambient conditions and cooling system), operating characteristics (*e.g.,* part-load operation and frequent starting and stopping), and reduced efficiency due to degradation. The standard also accommodates the full size range of turbines.

We also expect multiple technology developments to further increase the performance of new base load natural gas-fired stationary combustion turbines. Vendors continue to improve the single cycle efficiency of combustion turbines. The use of more efficient combustion turbine engines improves the overall efficiency of NGCC facilities. In addition, existing smaller NGCC facilities were likely designed using single or dual pressure HRSGs without a reheat cycle. New designs can incorporate three pressure steam generators with a reheat cycle to improve the overall efficiency of the NGCC facility. Finally, additional technologies to reduce emission rates for new combustion turbines include CHP and integrated non-emitting technologies. For example, an NGCC unit that is designed as a CHP unit where ten percent of the overall output is useful thermal output would have an emission rate approximately five percent less than an electric-only NGCC. In sum, we believe that our final emission standards of 1,000 lb CO_2/MWh-g and 1,030 lb CO_2/MW-n are not only readily achievable, but likely conservative.

b. Reconstructed Base Load Natural Gas-Fired Units

We disagree with commenters that stated that reconstructed combustion turbines will not be able to achieve the proposed emission standards. For the reasons listed below, we have concluded that an existing base load natural-gas fired unit that reconstructs can achieve an emission rate of 1,000 lb CO_2/MWh-g, regardless of its size.

Highly efficient NGCC units include (1) an efficient combustion turbine engine, (2) an efficient steam cycle, and (3) a combustion turbine exhaust system that is ''matched'' to the steam cycle for maximum efficiency. In order for an existing NGCC unit to trigger the reconstruction provisions, the unit would have to essentially be entirely rebuilt. This would involve extensive upgrades to both the combustion turbine engine and the HRSG. Therefore, a reconstructed NGCC unit will be able to maximize the efficiency of the turbine engine and the steam cycle and match the two for maximum efficiency.

According to comments submitted in response to the proposal for existing sources under CAA section 111(d), there are various options available to improve the efficiency of existing combustion turbines. One combustion turbine manufacturer provided comments describing specific technology upgrades for the compressor, combustor, and gas turbine components. This manufacturer stated that operators of existing turbines can replace older internal components along the gas path with state-of-the-art components that have higher aerodynamic efficiencies and improved seal designs. These gas-path enhancements enable existing sources to both improve the efficiency of the turbine engine and improve the systems used for cooling the metal parts along the hot-gas path to allow existing systems to achieve higher operating temperatures. In total, the manufacturer stated that utilities deploying these gas-path improvements on reconstructed industrial frame combustion turbines with nominal output ratings of 170 to 180 MW can increase their output by 10 MW while reducing CO_2 emissions by more than 2.6 percent compared to baseline. In addition to gas-path and software improvements, the manufacturer stated that the newest low-NO_X combustor designs can be retrofitted on modified and reconstructed turbines to achieve lower NO_X emissions, which improves turndown (*i.e.,* to enable stable operations at lower loads compared to the lowest stable load achievable at baseline conditions) and efficiencies across all load conditions. The manufacturer indicated that operators of existing combustion turbines deploying both state-of-the-art gas-path and software upgrades and combustor upgrades can increase output on frame-style turbines with nominal output ratings of 170 to 180 MW by 14 MW, while reducing CO_2 emissions by 2.8 percent. In addition to the preceding upgrades, the manufacturer stated that existing combustion turbines can achieve the largest efficiency improvements by upgrading existing compressors with more advanced compressor technologies, potentially improving the combustion turbine's efficiency by an additional 3.8 percent. Thus, the total potential CO_2 emissions reductions for just the combustion turbine portion of a combined cycle unit is 6.6 percent.

In addition to upgrades to the combustion turbine engine, an operator reconstructing a NGCC unit will have the opportunity to improve the efficiency of the HRSG and steam cycle. For example, a steam turbine manufacturer identified three retrofit technologies available for reducing the CO_2 emissions rate of existing steam turbines by 1.5 to 3 percent: (1) Steam-path upgrades can minimize aerodynamic and steam leakage losses; (2) replacement of the existing high pressure turbine stages with state-of-the-art stages capable of extracting more energy from the same steam supply; and (3) replacement of low-pressure turbine stages with larger diameter components that extract additional energy and that reduce velocities, wear, and corrosion.

In addition, an operator reconstructing a NGCC unit could upgrade the entire steam cycle. For example, combined cycle units originally constructed with only a single pressure level can be upgraded to also include second and third pressure levels. Studies [538] [539] [540] show that converting a single pressure HRSG with steam reheat to a double pressure configuration with steam reheat can reduce the CO_2 emission rate of a NGCC unit by 1.5 to 1.7 percent. These same studies show that converting from a single pressure configuration with reheat to a triple pressure configuration with reheat can yield a 1.8 to 2 percent reduction in the CO_2 emission rate. Similarly, units constructed with only a double pressure configuration without reheat can obtain a 0.4 percent reduction by adding a reheat cycle or a 0.9 percent reduction by converting to a triple pressure configuration and adding a reheat cycle. Existing NGCC turbines that convert to these advanced HRSG configurations and that deploy the previously discussed combustion turbine and steam turbine upgrades can

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[538] ''Exergetic and Economic Evaluation of the Effects of HRSG Configurations on the Performance of Combined Cycle Power Plants.'' M. Mansouri, *et al. Energy Conversion and Management* 58:47–58, 2012.

[539] ''Combined Cycle Power Plant Performance Analyses Based on Single-Pressure and Multipressure Heat Recovery Steam Generator.'' M. Rahim, *Journal of Energy Engineering,* 138:136–145, 2012.

[540] ''Thermodynamic Evaluation of Combined Cycle Plants.'' N. Woudstras *et al. Energy Conversion and Management* 51:1099–1110, 2010.

realize CO_2 emission rate reductions ranging from 6 to 10 percent, depending on their baseline design and condition. Based on the available options to improve the efficiency of existing NGCC units and the fact that the vast majority of existing NGCC units are already achieving emission rates of 1,000 lb CO_2/MWh-g or less, we have concluded that all reconstructed NGCC units can achieve this emission rate.

Finally, we note that an owner or operator that is considering reconstructing an existing simple cycle turbine should decide how they wish to operate that turbine in the future. If they anticipate operating above the percentage electric sales threshold, then they should install a HRSG and steam turbine and convert to a NGCC power block in accordance with our determination that NGCC is the BSER for base load applications. If they intend to operate the turbine below the percentage electric sales threshold, however, then the clean fuels standard, described below, will apply.

c. Newly Constructed and Reconstructed Non-Base Load Natural Gas-Fired Units

The EPA agrees with the commenters who stated that ‘‘no emission limit’’ would be inconsistent with the requirements of CAA 111(a)(1). We therefore are finalizing an input-based standard based on the use of clean fuels for non-base load natural gas-fired combustion turbines in recognition that efficiency can be reduced due to operation at low loads, cycling, and frequent startups. The EPA has concluded that, at this time, we do not have sufficient information to set a meaningful output-based standard for non-base load natural gas-fired combustion turbines. The input-based standard requires non-base load units to burn fuels with an average emission rate of 120 lb CO_2/MMBtu or less. This standard is readily achievable because the CO_2 emission rate of natural gas is 117 lb CO_2/MMBtu. The most common back up fuel is distillate oil, which has a CO_2 emission rate of 163 lb CO_2/MMBtu. A non-base load natural gas-fired combustion turbine burning 9 percent distillate oil and 91 percent natural gas has an emission rate of 121 lb CO_2/MMBtu, which rounds to 120 lb CO_2/MMBtu using two significant digits. Therefore, the vast majority of owners and operators of non-base load natural gas-fired combustion turbines will be able to achieve the standard using business-as-usual fuels.

While the emission reductions that will result from restricting the use of fuels with higher CO_2 emission rates is minor, the compliance burden is also minimal. Owners and operators of non-base load natural gas-fired combustion turbines burning fuels with consistent chemical compositions that meet the clean fuels requirement (*e.g.,* natural gas, ethane, ethylene, propane, naphtha, jet fuel kerosene, fuel oils No. 1 and 2, and biodiesel) will only need to maintain records that they burned these fuels in the combustion turbine. No additional recordkeeping or reporting will be required. Owners and operators burning fuels with higher CO_2 emission rates and/or chemical compositions that vary (*e.g.,* residual oil, non-jet fuel kerosene, landfill gas) will have to follow the procedures in part 98 of this part to determine the average CO_2 emission rate of the fuels burned during the applicable 12-operating-month compliance period and submit quarterly reports to verify that they are in compliance with the required emission standard.

d. Newly Constructed and Reconstructed Multi-Fuel-Fired Units

We also are finalizing an input-based standard based on the use of clean fuels, as opposed to an output-based standard, for multi-fuel units for several reasons. Specifically, we do not currently have continuous CO_2 emissions data for multi-fuel-fired units, we have not evaluated the potential efficiency impacts of different fuels, and the range of carbon content of non-natural gas fuels complicates establishing an appropriate output-based standard. Based on this lack of data, we have concluded that we cannot establish an output-based emission standard for multi-fuel-fired combustion turbines at this time.

The input-based emissions standard for this subcategory is based on the use of clean fuels. The use of clean fuels will ensure that newly constructed and reconstructed combustion turbines minimize CO_2 emissions during all periods of operation by limiting the use of fuels with higher CO_2 emission rates. To accurately represent the BSER and limit the ability of units to co-fire higher CO_2 emitting fuels with natural gas, we have concluded that it is necessary to use an equation based on the heat input from natural gas to determine the applicable emission standard. The 12-operating-month standard will vary from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu depending on the fraction of heat input from natural gas. The standard will be calculated by adding the product of the percent of heat input from natural gas and 120 with the product of the heat input from non-natural gas fuels and 160. For example, a combustion turbine that burns 80 percent natural gas and 20 percent distillate oil would be subject to an emission standard of 130 lb CO_2/MMBtu (rounded to two significant figures), which is equivalent to the actual emission rate of a unit burning this combination of fuels. On the other hand, a combustion turbine that burns 100 percent residual oil would be subject to an emission standard of 160 lb CO_2/MMBtu, but would have a higher actual emission rate, and would thus be out of compliance. In this way, the standard will restrict higher carbon fuels from being burned in multi-fuel-fired units, but will be readily achievable by units burning clean fuels.

According to information submitted to the EIA, the primary, non-natural gas fuels used by combustion turbines today for the production of electricity should all meet our definition of a clean fuel. Thus, while the emission reductions that will result from restricting the use of fuels with higher CO_2 emission rates is minor, the compliance burden is also minimal. Owners and operators of multi-fuel-fired combustion turbines burning fuels with consistent chemical compositions that meet the clean fuels requirement (*e.g.,* natural gas, ethylene, propane, naphtha, jet fuel kerosene, fuel oils No. 1 and 2, and biodiesel) will only need to maintain records that they burned these fuels in the combustion turbine. No additional recordkeeping or reporting will be required. Owners and operators burning fuels with higher CO_2 emission rates and/or chemical compositions that vary (*e.g.,* residual oil, non-jet fuel kerosene, landfill gas) will have to follow the procedures in part 98 of this part to determine the average CO_2 emission rate of the fuels burned during the applicable 12-operating-month compliance period and submit quarterly reports to verify that they are in compliance with the required emission standard.

e. Modified Units

The EPA is not finalizing the proposed emission standards for stationary combustion turbines that conduct modifications. As explained in Section XV below, we are withdrawing the June 2014 proposal with respect to these sources. We received a significant number of comments asserting that modified combustion turbines could not meet the proposed emission standards of 1,000 lb/MWh-g for large turbines and 1,100 lb/MWh-g for small turbines. For the reasons explained in Section IX.B.1 above, we have decided not to subcategorize combustion turbines based on size for a number of reasons and are setting a single standard of

1,000 lb/MWh-g for all base load natural gas-fired turbines instead. While we are confident that all new and reconstructed units will be able to achieve this standard, we are less confident that all smaller combustion turbines that undertake a modification, specifically those that were constructed prior to 2000, will be able to do so. Until we have the opportunity to further investigate the full range of modifications that turbine owners and operators might undertake, we consider it premature to finalize emission standards for these sources.

Combustion turbines have unique characteristics that make determining an appropriate emission standard for modified sources a more challenging task than for coal-fired boilers. For example, each combustion turbine engine has a specific corresponding combustor. The development of more efficient combustor upgrades for existing turbine designs typically requires manufacturers to expend considerable resources. Consequently, not all manufacturers offer combustor upgrades for smaller or older designs because it would be difficult to recoup their investment. In contrast, efficiency upgrades for boilers can generally be installed regardless of the specific boiler's characteristics.

In addition, natural gas has the lowest CO_2 emission rate (in terms of lb CO_2/MMBtu) of any fossil fuel. As a result, an owner or operator that adds the ability to burn a back up fuel, such as distillate oil, to an existing turbine would likely trigger an NSPS modification. This is a relatively low-capital-cost upgrade that would significantly increase a unit's potential hourly emission rate, even though the annual emissions increase would be relatively minor because operating permits generally limit the amount of distillate oil that a unit can burn. We need to conduct additional analysis to determine an appropriate emission standard for units that undertake this type of modification, which does not involve any of the combustion turbine components that impact efficiency.

To be clear, the EPA is not reaching a final decision that modifications should be subject to different requirements than we are finalizing in this rule for new and reconstructed sources. We have made no decisions, and this matter is not concluded. We plan to continue to gather information, consider the options for modifications, and develop a new proposal for modifications in the future. Therefore, the EPA is withdrawing the proposed standards for all combustion turbines that conduct modifications and is not issuing final standards for those sources at this time. See Section XV below. We note that the effect of this withdrawal is that modified combustion turbines will continue to be existing sources subject to section 111(d).[541]

X. Summary of Other Final Requirements for Newly Constructed, Modified, and Reconstructed Fossil Fuel-Fired Electric Utility Steam Generating Units and Stationary Combustion Turbines

This section describes the final action's requirements regarding startup, shutdown, and malfunction; continuous monitoring; emissions performance testing; continuous compliance; and notification, recordkeeping, and reporting for newly constructed, modified, and reconstructed affected steam generating units and combustion turbines. We also explain final decisions regarding several of these requirements.

A. Startup, Shutdown, and Malfunction Requirements

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the D.C. Circuit vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of hazardous air pollutants (HAP) during periods of startup, shutdown, and malfunction (SSM). Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), holding that under section 302(k) of the CAA, emissions standards or limitations must be continuous in nature and that the SSM exemption violates the CAA's requirement that some CAA section 112 standards apply continuously.

Consistent with *Sierra Club* v. *EPA,* the EPA has established standards in this rule that apply at all times. In establishing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained below as well as in Section V.J.1 above, has not established alternate standards for those periods. Specifically, startup and shutdown periods are included in the compliance calculation as periods of partial load. The final method to calculate compliance is to sum the emissions for all operating hours and to divide that value by the sum of the electric energy output (and useful thermal energy output, where applicable for affected CHP EGUs), over a rolling 12-operating-month period. In their compliance determinations, sources must incorporate emissions from all periods, including startup or shutdown, during which fuel is combusted and emissions are being monitored, in addition to all power produced over the periods of emissions measurements. As explained in Section V.J.1, given that the duration of startup or shutdown periods is expected to be small relative to the duration of periods of normal operation and that the fraction of power generated during periods of startup or shutdown is expected to be very small, the impact of these periods on the total average over a 12-operating-month period is expected to be minimal.

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. (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of 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. A malfunction should not be treated 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.

Further, accounting for malfunctions in setting emission standards would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the

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[541] As discussed above in Section VI.A of this preamble, a modified source that is not covered by a final or pending proposed standard continues to be an ''existing source'' and so will be covered by requirements under section 111(d). Under the definition of ''existing source'' in section 111(a)(6), an existing source is any source that is not a new source. Under the definition of ''new source'' in section 111(a)(2), a modified source is a new source only if the modification occurs after the publication of regulations (or proposed regulations, if earlier) that will be applicable to that source. Because we are not finalizing regulations with respect to modified steam turbines, and are withdrawing the proposal with respect to such sources, there are neither final regulations nor pending proposed regulations which will be applicable to such modifications.

category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not ''reasonably'' foreseeable. See, *e.g., Sierra Club* v. *EPA,* 167 F.3d 658, 662 (D.C. Cir. 1999) (''The EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to 'invest the resources to conduct the perfect study.' '') See also, *Weyerhaeuser v Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978) (''In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.''). In addition, emissions during a malfunction event can be significantly higher than emissions at any other time of source operation. For example, if an air pollution control device with 99 percent removal goes off-line as a result of a malfunction (as might happen if, for example, the bags in a baghouse catch fire) and the emission unit is a steady state type unit that would take days to shut down, the source would go from 99 percent control to zero control until the control device was repaired. The source's emissions during the malfunction would be 100 times higher than during normal operations. As such, the emissions over a 4-day malfunction period would exceed the annual emissions of the source during normal operations. As this example illustrates, accounting for malfunctions could lead to standards that are not reflective of (and significantly less stringent than) levels that are achieved by a well-performing, non-malfunctioning source. It is reasonable to interpret CAA section 111 to avoid such a result. The EPA's approach to malfunctions is consistent with CAA section 111 and is a reasonable interpretation of the statute.

Given that compliance with the emission standard is determined on a 12-operating-month rolling average basis, the impact of periods of malfunctions on the total average over a 12-operating-month period is expected to be minimal. Thus, malfunctions over that period are not likely to result in a violation of the standard.

In the unlikely event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, sudden, infrequent, not reasonably preventable and was not instead caused in part by poor maintenance or careless operation. 40 CFR 60.2 (definition of malfunction).

If the EPA determines in a particular case that an enforcement action against a source for violation of an emission standard is warranted, the source can raise any and all defenses in that enforcement action and the federal district court will determine what, if any, relief is appropriate. The same is true for citizen enforcement actions. Similarly, the presiding officer in an administrative proceeding can consider any defense raised and determine whether administrative penalties are appropriate.

In summary, the EPA interpretation of the CAA and, in particular, CAA section 111 is reasonable and encourages practices that will avoid malfunctions. Administrative and judicial procedures for addressing exceedances of the standards fully recognize that violations may occur despite good faith efforts to comply and can accommodate those situations.

In the January 2014 proposal for newly constructed EGUs, the EPA had proposed to include an affirmative defense to civil penalties for violations caused by malfunctions in an effort to create a system that incorporates some flexibility, recognizing that there is a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission standards may be violated under circumstances entirely beyond the control of the source. Although the EPA recognized that its case-by-case enforcement discretion provides sufficient flexibility in these circumstances, it included the affirmative defense to provide a more formalized approach and more regulatory clarity. See *Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal case-by-case enforcement discretion approach is adequate); *but see Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977) (requiring a more formalized approach to consideration of ''upsets beyond the control of the permit holder''). Under the EPA's regulatory affirmative defense provisions, if a source could demonstrate in a judicial or administrative proceeding that it had met the requirements of the affirmative defense in the regulation, civil penalties would not be assessed. Recently, the U.S. Court of Appeals for the District of Columbia Circuit vacated an affirmative defense in one of the EPA's CAA section 112 regulations. *NRDC* v. *EPA,* 749 F.3d 1055 (D.C. Cir., 2014) (vacating affirmative defense provisions in CAA section 112 rule establishing emission standards for Portland cement kilns). The court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts in such cases lies exclusively with the courts, not the EPA. Specifically, the Court found: ''As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are 'appropriate.''' *See NRDC* at 1063 (''[U]nder this statute, deciding whether penalties are 'appropriate' in a given private civil suit is a job for the courts, not EPA.'').[542] In light of *NRDC,* the EPA is not including a regulatory affirmative defense provision in this final rule. As explained above, if a source is unable to comply with emissions standards as a result of a malfunction, the EPA may use its case-by-case enforcement discretion to provide flexibility, as appropriate. Further, as the D.C. Circuit recognized, in an EPA or citizen enforcement action, the court has the discretion to consider any defense raised and determine whether penalties are appropriate. *Cf. NRDC,* at 1064 (arguments that violations were caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same is true for the presiding officer in EPA administrative enforcement actions.[543]

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[542] The court's reasoning in *NRDC* focuses on civil judicial actions. The court noted that ''EPA's ability to determine whether penalties should be assessed for Clean Air Act violations extends only to administrative penalties, not to civil penalties imposed by a court.'' *Id.*

[543] Although the *NRDC* case does not address the EPA's authority to establish an affirmative defense to penalties that is available in administrative enforcement actions, the EPA is not including such an affirmative defense in the final rule. As explained above, such an affirmative defense is not necessary. Moreover, assessment of penalties for violations caused by malfunctions in administrative

Continued

B. Continuous Monitoring Requirements

The majority of comments received on the proposal supported the EPA's use of existing monitoring requirements under the Acid Rain Program, which are contained in 40 CFR part 75 requirements. In response to this, the EPA is finalizing monitoring requirements that incorporate and reference the part 75 monitoring requirements for the majority of the CO_2 and energy output monitoring requirements while ensuring accuracy and stringency required under the program.

This final rule requires owners or operators of EGUs that combust solid fossil fuel to install, certify, maintain, and operate continuous emission monitoring systems (CEMS) to measure CO_2 concentration, stack gas flow rate, and (if needed) stack gas moisture content in accordance with 40 CFR part 75, in order to determine hourly CO_2 mass emissions rates (tons/hr).

The rule allows owners or operators of affected EGUs that burn exclusively gaseous or liquid fuels to install fuel flow meters as an alternative to CEMS and to calculate the hourly CO_2 mass emissions rates using Equation G–4 in appendix G of part 75. To implement this option, hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of the fuel are also required, in accordance with appendix D of part 75.

In addition to requiring monitoring of the CO_2 mass emission rate, the rule requires EGU owners or operators to monitor the hourly unit operating time and ''gross output'', expressed in megawatt hours (MWh). The gross output includes electrical output plus any mechanical output, plus 75 percent of any useful thermal output.

The rule requires EGU owners or operators to prepare and submit a monitoring plan that includes both electronic and hard copy components, in accordance with 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan should be submitted to the EPA's CAMD using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. The hard copy portion of the plan should be sent to the applicable state and EPA Regional office. Further, all monitoring systems used to determine the CO_2 mass emission rates have to be certified according to 40 CFR 75.20 and section 6 of part 75, appendix A within the 180-day window of time allotted under 40 CFR 75.4(b), and are required to meet the applicable on-going quality assurance procedures in appendices B and D of part 75.

The rule requires all valid data collected and recorded by the monitoring systems (including data recorded during startup, shutdown, and malfunction) to be used in assessing compliance. Failure to collect and record required data is a violation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of stack emissions (*e.g.,* calibration error tests, linearity checks, and required zero and span adjustments).

The rule requires only those operating hours in which valid data are collected and recorded for all of the parameters in the CO_2 mass emission rate equation to be used for calculating compliance with applicable emission limits. Additionally for EGUs using CO_2 CEMS, only unadjusted stack gas flow rate values should be used in the emissions calculations. In this rule, part 75 bias adjustment factors (BAFs) should not be applied to the flow rate data. These restrictions on the use of part 75 data for part 60 compliance are consistent with previous NSPS regulations and revisions. Additionally if an affected EGU combusts natural gas and/or fuel oil and the CO_2 mass emissions rate are measured using Equation G–4 in appendix G of part 75, then determination of site-specific carbon-based F-factors using Equation F–7b in section 3.3.6 of appendix F of part 75 is allowed, and use of these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature is also allowed.

This final rule includes the following special compliance provisions for units with common stack or multiple stack configurations; these provisions are consistent with 40 CFR 60.13(g):

- If two or more EGUs share a common exhaust stack, are subject to the same emission limit, and the operator is required to (or elects to) determine compliance using CEMS, then monitoring the hourly CO_2 mass emission rate at the common stack instead of monitoring each EGU separately is allowed. If this option is chosen, the hourly gross electrical load (or steam load) is the sum of the hourly loads for the individual EGUs and the operating time is expressed as ''stack operating hours'' (as defined in 40 CFR 72.2). Then, if compliance with the applicable emission limit is attained at the common stack, each EGU sharing the stack will be in compliance with the CO_2 emissions limit.
- If the operator is required to (or elects to) determine compliance using CEMS and the effluent from the EGU discharges to the atmosphere through multiple stacks (or, if the effluent is fed to a stack through multiple ducts and is monitored in the ducts), then monitoring the hourly CO_2 mass emission rate and the ''stack operating time'' at each stack or duct separately is required. In this case, compliance with the applicable emission limit is determined by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross output for the unit.

The rule requires 95 percent of the operating hours in each compliance period (including the compliance periods for the intermediate emission limits) to be valid hours, *i.e.,* operating hours in which quality-assured data are collected and recorded for all of the parameters used to calculate CO_2 mass emissions. EGU owners or operators have the option to use back up monitoring systems, as provided in 40 CFR 75.10(e) and 75.20(d), to help meet this data capture requirement. This requirement is separate from the requirement for a source to demonstrate compliance with an applicable emission standard. When demonstrating compliance with an emission standard the calculation must use all valid data to calculate a compliance average even if the percent of valid hours recorded in the period is less than the 95 percent requirement.

C. Emissions Performance Testing Requirements

Similarly to the comments received on monitoring for the proposal, commenters in general supported the use of current testing requirements required under the Acid Rain Program 40 CFR part 75 requirements. Thus the EPA is finalizing requirements for performance testing as consistent with part 75 requirements where appropriate to ensure the quality and accuracy of data and measurements as required by the final rule.

In accordance with 40 CFR 75.64(a), the final rule requires an EGU owner or operator to begin reporting emissions data when monitoring system certification is completed or when the 180-day window in 40 CFR 75.4(b) allotted for initial certification of the monitoring systems expires (whichever date is earlier). For EGUs subject to the

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proceedings and judicial proceedings should be consistent. *Cf.* CAA section 113(e) (requiring both the Administrator and the court to take specified criteria into account when assessing penalties).

1,400 lb CO_2/MWh-g) emission standard, the initial performance test consists of the first 12 operating months of data, starting with the month in which emissions are first required to be reported. The initial 12-operating-month compliance period begins with the first month of the first calendar year of EGU operation in which the facility exceeds the capacity factor applicability threshold.

The traditional 3-run performance tests (*i.e.,* stack tests) described in 40 CFR 60.8 are not required for this rule. Following the initial compliance determination, the emission standard is met on a 12-operating-month rolling average basis.

D. Continuous Compliance Requirements

Commenters supported the use of a 12-operating-month rolling average for the compliance period for the final standards. In response, this final rule specifies that compliance with the 1,400 lb CO_2/MWh-g emission limit is determined on a 12-operating-month rolling average basis, updated after each new operating month. For each 12-operating-month compliance period, quality-assured data from the certified Part 75 monitoring systems is used together with the gross output over that period of time to calculate the average CO_2 mass emissions rate.

The rule specifies that the first operating month included in the initial 12-operating-month compliance period is the month in which reporting of emissions data is required to begin under 40 CFR 75.64(a), *i.e.,* either the month in which monitoring system certification is completed or the month in which the 180-day window allotted to finish certification testing expires (whichever month is earlier).

Initial compliance with the applicable emissions limit in kg/MWh is calculated by dividing the sum of the hourly CO_2 mass emissions values by the total gross output for the 12-operating-month period. Affected EGUs continue to be subject to the standards and maintenance requirements in the CAA section 111 regulatory general provisions contained in 40 CFR part 60, subpart A.

Several commenters stated that the final rule should require operators to round their calculated emissions rates to three significant figures when comparing their actual rates to the standard. These commenters said that allowing use of only two significant digits when calculating the 12-operating-month rolling average emission rate would constitute relaxation of the standard by 5 percent because an actual emission rate of 1,049.9 lb CO_2/MWh rounds to 1,000 lb of CO_2 per MWh when only two significant figures are required in the final step of compliance calculations. Commenters also suggested that the emission limits be written in scientific notation (*e.g.,* 1.10 x 10 − 3 lb CO_2/MWh) to clarify the number of significant digits that should be used when evaluating compliance. Other commenters suggested that the final step in compliance calculations should reflect rounding the emission rate to the nearest whole number using the ASTM rounding convention (ASTM E29).

The General Provisions of Part 60 specify the rounding conventions for compliance calculations at 40 CFR 60.13(h)(3) including the provision that ''after conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.''

The final rule requires that the 12-operating-month rolling average emission rate must be rounded to three significant figures if the applicable emissions standard is greater than or equal to 1,000 (*e.g.,* an actual emission rate of 1,004.9 lb CO_2/MWh is rounded to 1,000 lb CO_2/MWh); for standards of 1000 or less, the final rule requires rounding the actual emission rate to two significant figures (*e.g.,* an actual emission rate of 454.9 kg CO_2/MWh is rounded to 450 kg CO_2/MWh). Historically, many of the emissions limits under part 60 have been expressed to two significant digits (*e.g.,* the original SO_2 emission standard for coal-fired units under Subpart D was 1.2 lb SO_2/MMBtu). The rounding conventions under the General Provisions allow the reporting of all emission rates in the range from 1.15 to 1.249 as 1.2 lb SO_2/MMBtu. During compliance periods with emissions at the lower end of this range, the operator is required to report higher emissions than actually occurred; during compliance periods at the upper end of this range the operator is allowed to report lower emissions than actually occurred. In either case the absolute error remains small because the emission rate in this example is a relatively small numerical value. In addition, the required emission reductions typically are large enough that rounding does not impact the emission control strategy of affected units. However, the final standards for CO_2 emissions include numerical values that are larger than many historical emissions standards and require a relatively small percent reduction in emissions. Accordingly, it is appropriate to require the use of three significant digits when completing compliance calculations resulting in numerical values larger than 1,000. This is particularly important when considering the relatively small emission rate changes that may be required for compliance with the unit-specific emission standards being finalized for modified steam generating and IGCC units because a rounding error of 5 percent may be larger than the percent difference between the affected unit's historically best emission rate and the emission rate immediately preceding the modification.

The final rule requires rounding of emission rates with numerical values greater than or equal to 1,000 to three significant figures and rounding of rates with numerical values less than 1,000 to two significant figures.

E. Notification, Recordkeeping, and Reporting Requirements

Commenters supported the coordination of notification, recordkeeping, and reporting required under this rule in conjunction with the requirements already in place under part 75, so the EPA has made the requirements as efficient and streamlined as possible with the current requirements under part 75. The final rule requires an EGU owner or operator to comply with the applicable notification requirements in 40 CFR 75.61, 40 CFR 60.7(a)(1) and (a)(3), and 40 CFR 60.19. The rule also requires the applicable recordkeeping requirements in subpart F of part 75 to be met. For EGUs using CEMS, the data elements that are recorded include, among others, hourly CO_2 concentration, stack gas flow rate, stack gas moisture content (if needed), unit operating time, and gross electric generation. For EGUs that exclusively combust liquid and/or gaseous fuel(s) and elect to determine CO_2 emissions using Equation G–4 in appendix G of part 75, the key data elements in subpart F that are recorded include hourly fuel flow rates, fuel usage times, fuel GCV, gross electric generation.

The rule requires EGU owners or operators to keep records of the calculations they perform to determine the total CO_2 mass emissions and gross output for each operating month. Records of the calculations performed to determine the average CO_2 mass emission rate (kg/MWh) and the percentage of valid CO_2 mass emission rates in each compliance period are required to be kept. The rule also requires sources to keep records of calculations performed to determine site-specific carbon-based F-factors for use in Equation G–4 of part 75, appendix G (if applicable).

Sources are required to keep all records for a period of 3 years. All required records must be kept on-site for a minimum of two years, after which the records can be maintained off-site.

The rule requires all affected EGU owners/operators to submit quarterly electronic emissions reports in accordance with subpart G of part 75. The reports in appendix G that do not include data required to calculate compliance with the applicable CO_2 emission standard are not required to be reported under this rule. The rule requires the reports in 40 CFR 60.5555 to be submitted using the ECMPS Client Tool. Except for a few EGUs that may be exempt from the Acid Rain Program (*e.g.,* oil-fired units), this is not a new reporting requirement. Sources subject to the Acid Rain Program are already required to report the hourly CO_2 mass emission rates that are needed to assess compliance with this rule.

Additionally, in the final rule and as part of an agency-wide effort to streamline and facilitate the reporting of environmental data, the rule requires selected data elements that pertain to compliance under this rule, and that serve the purpose of identifying violations of an emission standard, to be reported periodically using ECMPS.

Specifically, EGU owners/operators must submit quarterly electronic reports within 30 days after the end of each quarter consistent with current part 75 reporting requirements. The first report is for the quarter that includes the final (12th) operating month of the initial 12-operating-month compliance period. For that initial report and any subsequent report in which the 12th operating month of a compliance period (or periods) occurs during the calendar quarter, the average CO_2 mass emissions rate (kg/MWh) is reported for each compliance period, along with the dates (year and month) of the first and twelfth operating months in the compliance period and the percentage of valid CO_2 mass emission rates obtained in the compliance period. The dates of the first and last operating months in the compliance period clearly bracket the period used in the determination, which facilitates auditing of the data. Reporting the percentage of valid CO_2 mass emission rates is necessary to demonstrate compliance with the requirement to obtain valid data for 95 percent of the operating hours in each compliance period. Any violations that occur during the quarter are identified. If there are no compliance periods that end in the quarter, a definitive statement to that effect must be included in the report. If one or more compliance periods end in the quarter but there are no violations, a statement to that effect must be included in the report.

Currently, ECMPS is not programmed to receive the additional information included in the report required under 40 CFR 60.5555(a)(2) for affected EGUs. However, we will make the necessary modifications to the system in order to fully implement the reporting requirements of this rule upon promulgation.

XI. Consistency Between BSER Determinations for This Rule and the Rule for Existing EGUs

In the CAA section 111(d) rule for existing steam units and combustion turbines that the EPA is promulgating at the same time as this CAA section 111(b) rule, the EPA is identifying as part of the BSER for those sources, building block 1 (for steam units, efficient operation), building block 2 (for steam units, dispatch shift to existing NGCC units), and building block 3 (for steam units and combustion turbines, substitution of generation with new renewable energy). In this section, we explain why the EPA is not identifying building blocks 1, 2, or 3 as part of the BSER for new, modified, or reconstructed steam generators or combustion turbines.

A. Newly Constructed Steam Generating Units

1. Preference for Technological Controls as the BSER for New EGUs

As discussed in this preamble and in more detail in the preamble to the CAA section 111(d) rule for existing sources, the phrase ''system of emission reduction'' is undefined and provides the EPA with discretion in setting a standard of performance under CAA section 111(b) or emission guidelines under CAA section 111(d). Because the phrase by its plain language does not limit our review of potential systems in either context, the same systems could be considered for application in new and existing sources. That said, many other factors and considerations direct us to focus on different systems when establishing a standard of performance under CAA section 111(b) and an emission guideline under CAA section 111(d). Thus, it is useful to describe part of the underlying basis for the BSER—partial CCS—that the EPA has determined for new steam units before discussing the building blocks that form the BSER for existing units.

For new steam generating units, the EPA is identifying, as the BSER, systems of emission reduction that assure that these sources are inherently low-emitting at the time of construction. The following reasons support this approach to the BSER.

New sources are expected to have long operating lives over which initial capital costs can be amortized. Thus, new construction is the preferred time to drive capital investment in emission controls. In this case, the BSER for new steam generators, partial CCS, requires substantial capital expenditures, which new sources are best able to accommodate.

While CAA section 111(b)(1)(B) and (a)(1) by their terms do not mandate that the BSER assure that new sources are inherently low emitting, that approach to the BSER is consistent with the legislative history.[544] See Section III.H.3.b.4 above. For instance, the 1970 Senate Committee Report explains that ''[t]he overriding purpose of this section [concerning new source performance standards] would be to prevent new air pollution problems, and toward that end, *maximum feasible control of new sources at the time of their construction* is seen by the committee as the most effective and, in the long run, the least expensive approach.'' [545] Existing sources, on the other hand, would be regulated through emission standards, which were broadly understood at the time to reflect available technology, alternative methods of prevention and control, alternative fuels, processes, and operating methods.[546] [547]

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[544] Although Congress expressed a clear preference that new sources would be ''designed, built, equipped, operated, and maintained so as to reduce emissions to a minimum,'' the Senate Committee Report also makes clear that the term standard of performance ''refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, *or other methods.''* Sen. Rep. No. 91–1196 at 15–17, 1970 CAA Legis. Hist. at 415–17 (emphasis added).

[545] Sen. Rep. No. 91–1196 at 15–16, 1970 CAA Legis. Hist. at 416 (emphasis added).

[546] *See* 1970 CAA Amendments, Pub. L. 91–604, section 4, 84 Stat. 1676, 1679 (Dec. 31, 1970) (describing information that the EPA must issue to the states and appropriate air pollution control agencies along with the issuance of ambient air quality criteria under Section 4 of the 1970 CAA titled ''Ambient Air Quality and Emission Standards'').

[547] In the 1977 CAA Amendments, Congress revised section 111(a)(1) to mandate that the EPA base standards for new sources on technological controls, but, at the same time, made clear that the EPA was not required to base the emission guidelines for existing sources on technological controls. In the 1990 CAA Amendments, Congress repealed the section 111(a)(1) requirements that distinguished between new and existing sources and largely restored the 1970 CAA Amendments version of section 111(a)(1).

2. Practical Implications of Including the Building Blocks

Several practical considerations make the building blocks inappropriate for new sources. Thus, for the following reasons, the EPA does not consider it appropriate to include the building blocks as part of the BSER for new sources:

a. Additional Cost

Partial CCS will impose substantial (albeit reasonable) costs on new steam-generating EGUs, and, as a result, the EPA does not believe that including additional measures as part of the BSER would be appropriate. One disadvantage in adding additional costs is that doing so would make it more difficult for new steam-generating EGUs to compete with new nuclear units. Because the BSER is selected after considering cost (among other factors), the EPA is not required to,[548] and in this case believes it would not be appropriate to, select the most stringent adequately demonstrated system of emission reduction (through the combination of partial CCS and the building blocks) for purposes of setting a standard of performance under CAA section 111(b).

Building block 1 measures are not appropriate (or would be redundant) because the BSER for new steam generating units is based on highly efficient supercritical technology, *i.e.,* state-of-the-art, efficient equipment. See Section V.K above. Accordingly, there is little improvement in efficiency that can be justified as part of the BSER.

Building block 2 and 3 measures are not appropriate for the BSER because new steam units would have a significantly limited range of options to implement building blocks 2 and 3. The new source performance standard was proposed and is being finalized as a rate-based standard. Thus, if building blocks 2 and 3 were included in the BSER, a more stringent rate-based standard would be applicable to all new sources. However, it is conceivable that the EPA could propose a hybrid standard that would include both an emission-rate limit that reflects partial CCS and a requirement for allowances that reflects building blocks 2 and 3. Accordingly, the following discussion assumes either a rate-based or mass-based standard, or part of a hybrid standard.

In both a rate-based program and a mass-based program, building blocks 2 and 3 measures can be implemented through a range of methods, including trading with other EGUs. While it is not necessarily the case that every existing source will be able to implement each of the methods, in general, existing sources will have a range of measures to choose from. However, at least some of those methods may not be available to new sources, which would render compliance with their emission limits more challenging and potentially more costly.

One example is emission trading with other affected EGUs. For existing sources, emission trading is an important option for implementing the building blocks. There are large numbers of existing sources, and they will become subject to the section 111(d) standards of performance at the same time. It may be more cost-effective for some to implement the building blocks than others, and, as a result, some may over-comply and some may under-comply, and the two groups may trade with each other. Because of the large numbers of existing sources, the trading market can be expected to be robust. Trading optimizes efficiency. As a result, existing sources have more flexibility in the overall amount of their investment in building blocks 2 and 3 and can adjust investment obligations among themselves through emissions trading.

In contrast, new sources construct one at a time, and it is unknown how many new sources there will be. Without a sizeable number of new sources, there will not be a robust trading market. Thus, a new source cannot count on being able to find a new source trading partner. In addition, it is not possible to count on new sources being able to trade with existing sources, for several reasons. First, as noted, there are indications in the legislative history that new sources should be well-controlled at the source, which casts doubt on whether new sources should be allowed to meet their standards through the purchase of emission credits. Second, new sources must meet their standards of performance as soon as they begin operations. If they do so before the year 2022, when existing sources become subject to section 111(d) state plan standards of performance, no existing sources will be available as trading partners.

In addition, for section 111(d) sources, we are granting a 7-year period of lead-time for the implementation of the building blocks. This is due, in part, to the benefits of allowing the ERC and allowance markets to develop. However, the new source standards take effect immediately, so new sources would not have the advantage of this lead time were they subject to more stringent standards that also reflected the building blocks.[549]

In addition, if there are an unexpectedly large number of new sources, then they would be obliged to invest in greater amounts of building blocks 2 and 3, and that could reduce the amounts of building blocks 2 and 3 available for existing sources, and thereby raise the costs of building blocks 2 and 3 for existing sources. This could compromise the BSER under section 111(d) and undermine the ability of existing sources to comply with their section 111(d) obligations.[550]

B. New Combustion Turbines

For new combustion turbines, the building blocks are not appropriate as part of the BSER either. Building block 1 is limited to steam generating units, and therefore has no applicability to new combustion turbines. Measures comparable to those in building block 1 would not be appropriate because new highly efficient NGCC construction already entails high efficiency equipment and operation. Building block 2 is also limited to steam generating units and is not appropriate as part of the BSER for new NGCC units because it would not result in any emission reductions.

The reasons why building block 3 are not appropriate are the same as discussed above for why building blocks 2 and 3 are not appropriate for new steam generating units (limited range of options for implementation (including lack of availability of trading), lack of

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[548] For example, as early as a 1979 NSPS rulemaking for affected EGUs, the EPA recognized that it was not required to establish as the BSER the most stringent adequately demonstrated system of emission reduction available, and instead could weigh the amount of additional emission reductions against the costs. *See* 44 FR 52792, 52798 (Sept. 10, 1979) (''Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has potential for requiring) the imposition of a more stringent emission standard in several situations.'').

[549] At least in theory, we could consider promulgating a standard of performance for new affected EGUs that becomes more stringent beginning in 7 years, based on a more stringent BSER. We are not inclined to adopt that approach because section 111(b)(1)(B) requires that we review and, if necessary, revise the section 111(b) standards of performance no later than every 8 years anyway.

[550] The EPA is authorized to consider the BSER for new and existing sources in conjunction with each other. In the 1977 CAA Amendments, Congress revised section 111(a)(1) to require technological controls for new combustion sources at least in part because this requirement would preclude new sources from relying on low-sulfur coal to achieve their emission limits, which, in turn, would free up low-sulfur coal for existing sources.

lead-time for implementation, and the possibility of reducing the availability of renewable energy for existing sources).

C. Modified and Reconstructed Steam and NGCC Units

For modified and reconstructed steam generators, the EPA identified the BSER as maintenance of high efficiency or implementation of a highly efficient unit. The resulting emission limit must be met over the specified time period and cannot be deviated from or averaged. As a result, a modified or reconstructed steam generator generally will require ongoing maintenance and may find it prudent to operate below its limit as a safety margin. This represents a substantial commitment of resources. For these units, the additional costs of implementing the building blocks would not be appropriate.

In addition, building block 1 is not appropriate for modified or reconstructed steam generating units because the BSER for these units is already based on highly efficient performance. For the same reasons, it does not make sense to attempt to develop the analogue to building block 1 for reconstructed NGCC units—the BSER for them, too, is already based on highly efficient performance.

Building block 2 is not appropriate for reconstructed NGCC units because it would not yield any reductions.

Building blocks 2 and 3 are not appropriate for modified or reconstructed steam generators, and building block 3 is not appropriate for reconstructed NGCC units, for the same reasons that they are not appropriate for new EGUs, as described above (limited range of options for implementation (including lack of availability of trading), lack of lead-time for implementation, and the possibility of reducing the availability of renewable energy for existing sources).

XII. Interactions With Other EPA Programs and Rules

A. Overview

This final rule will, for the first time, regulate GHGs under CAA section 111. In Section IX of the preamble to the proposed rule, the EPA addressed how regulation of GHGs under CAA section 111 could have implications for other EPA rules and for permits written under the CAA Prevention of Significant Deterioration (PSD) preconstruction permit program and the CAA Title V operating permit program. The EPA proposed to adopt provisions in the regulations that explicitly addressed some of these implications.

For purpose of the PSD program, the EPA is finalizing provisions in part 60 of its regulations that make clear that the threshold for determining whether a PSD source must satisfy the BACT requirement for GHGs continues to apply after promulgation of this rule. This rule does not require any additional revisions to State Implementation Plans. As discussed further below, this final rule may have bearing on the determination of BACT for new, modified, and reconstructed EGUs that require PSD permits. With respect to the Title V operating permits program, this rule does not affect whether sources are subject to the requirement to obtain a Title V operating permit based solely on emitting or having the potential to emit GHGs above major source thresholds. However, this rule does have some implications for Title V fees, which the EPA is addressing in this final rule.

Finally, the fossil fuel-fired EGUs covered in this rule are or will be potentially impacted by several other recently finalized or proposed EPA rules, and such potential interactions with other EPA rules are discussed below.

B. Applicability of Tailoring Rule Thresholds Under the PSD Program

In our January 8, 2014 proposal, the EPA proposed to adopt regulatory language in 40 CFR part 60 that would ensure the promulgation of this NSPS would not undercut the application of rules that limit the application of the PSD permitting program requirements to only the largest sources of GHGs. An intervening decision of the United States Supreme Court has, to a large extent, resolved the legal issue that led the EPA to propose these part 60 provisions. The Supreme Court has since clarified that the PSD program does not apply to smaller sources based on the amount of GHGs they emit. However, because the largest sources emitting GHGs remain subject to the PSD permitting requirements, the EPA has concluded that it remains appropriate to adopt the proposed regulatory provisions in 40 CFR part 60 in this rule. We discuss our reasons for this action in detail below.

Under the PSD program in part C of title I of the CAA, in areas that are classified as attainment or unclassifiable for NAAQS pollutants, a new or modified source that emits any air pollutant subject to regulation at or above specified thresholds is required to obtain a preconstruction permit. This permit assures that the source meets specific requirements, including application of BACT to each pollutant subject to regulation under the CAA. Many states (and local districts) are authorized by the EPA to administer the PSD program and to issue PSD permits. If a state is not authorized, then the EPA issues the PSD permits for facilities in that state.

To identify the pollutants subject to the PSD permitting program, EPA regulations contain a definition of the term ''regulated NSR pollutant.'' 40 CFR 52.21(b)(50); 40 CFR 51.166(b)(49). This definition contains four subparts, which cover pollutants regulated under various parts of the CAA. The second subpart covers pollutants regulated under section 111 of the CAA. The fourth subpart is a catch-all provision that applies to ''[a]ny pollutant that is otherwise subjection to regulation under the Act.''

This definition and the associated PSD permitting requirements applied to GHGs for the first time on January 2, 2011, by virtue of the EPA's regulation of GHG emissions from motor vehicles, which first took effect on that same date. 75 FR 17004 (Apr. 2, 2010). As such, GHGs became subject to regulation under the CAA and the fourth subpart of the ''regulated NSR pollutant'' definition became applicable to GHGs.

On June 3, 2010, the EPA issued a final rule, known as the Tailoring Rule, which phased in permitting requirements for GHG emissions from stationary sources under the CAA PSD and Title V permitting programs (75 FR 31514). Under its understanding of the CAA at the time, the EPA believed the Tailoring Rule was necessary to avoid a sudden and unmanageable increase in the number of sources that would be required to obtain PSD and Title V permits under the CAA because the sources emitted GHGs emissions over applicable major source and major modification thresholds. In Step 1 of the Tailoring Rule, which began on January 2, 2011, the EPA limited application of PSD or Title V requirements to sources of GHG emissions only if the sources were subject to PSD or Title V ''anyway'' due to their emissions of non-GHG pollutants. These sources are referred to as ''anyway sources.'' In Step 2 of the Tailoring Rule, which began on July 1, 2011, the EPA applied the PSD and Title V permitting requirements under the CAA to sources that were classified as major, and, thus, required to obtain a permit, based solely on their potential GHG emissions and to modifications of otherwise major sources that required a PSD permit because they increased only GHG emissions above applicable levels in the EPA regulations.

In the PSD program, the EPA implemented the steps of the Tailoring Rule by adopting a definition of the term ''subject to regulation.'' The limitations in Step 1 of the Tailoring Rule are reflected in 40 CFR 52.21(b)(49)(iv) and 40 CFR 51.166(b)(48)(iv). With respect to ''anyway sources'' covered by PSD during Step 1, this provision established that GHGs would not be subject to PSD requirements unless the source emitted GHGs in the amount of 75,000 tons per year (tpy) of carbon dioxide equivalent (CO_2e) or more. The primary practical effect of this paragraph is that the PSD BACT requirement does not apply to GHG emissions from an ''anyway source'' unless the source emits GHGs at or above this threshold. The Tailoring Rule Step 2 limitations are reflected in 40 CFR 52.21(b)(49)(v) and 51.166(b)(48)(v). These provisions contain thresholds that, when applied through the definition of ''regulated NSR pollutant,'' function to limit the scope of the terms ''major stationary source'' and ''major modification'' that determine whether a source is required to obtain a PSD permit. See *e.g.* 40 CFR 51.166(a)(7)(i) and (iii); 40 CFR 51.166(b)(1); 40 CFR 51.166(b)(2).

This structure of the EPA's PSD regulations created questions regarding the extent to which the limitations in the Tailoring Rule would continue to apply to GHGs once they became regulated, through this final rule, under section 111 of the CAA. 79 FR 1487–1488. As discussed above, the definition of ''regulated NSR pollutant'' in the PSD regulations contains a separate PSD trigger for air pollutants regulated under the NSPS, 40 CFR 51.166(b)(49)(ii) (the ''NSPS trigger provision''). Thus, when GHGs become subject to a standard promulgated under CAA section 111 for the first time under this rule, PSD requirements would presumably apply for GHGs on an additional basis besides through the regulation of GHGs from motor vehicles. However, the Tailoring Rule, on the face of its regulatory provisions, incorporated the revised thresholds it promulgated into only the fourth subpart of the PSD definition of regulated NSR pollutant (''[a]ny pollutant that otherwise is subject to regulation under the Act''). The regulatory text does not clearly incorporate the thresholds into the NSPS trigger provision in the second subpart (''[a]ny pollutant that is subject to any standard promulgated under section 111 of the Act''). For this reason, a question arose as to whether the Tailoring Rule limitations would continue to apply to the PSD requirements after they are independently triggered for GHGs by the NSPS that the EPA is now promulgating. Stakeholders questioned whether the EPA must revise its PSD regulations —and, by the same token, whether states must revise their SIPs— to assure that the Tailoring Rule thresholds will continue to apply to sources potentially subject to PSD under the CAA based on GHG emissions.

In the January 8, 2014 proposed rule, the EPA explained that the agency had included an interpretation in the Tailoring Rule preamble, which means that the Tailoring Rule thresholds continue to apply if and when the EPA promulgates requirements under CAA section 111. 79 FR 1488 (citing 75 FR 31582). Nevertheless, to ensure there would be no uncertainty as to this issue, the EPA proposed to adopt explicit language in 40 CFR 60.46Da(j), 40 CFR 60.4315(b), and 40 CFR 60.5515 of the agency's regulations. The proposed language makes clear that the thresholds for GHGs in the EPA's PSD definition of ''subject to regulation'' apply through the second subpart of the definition of ''regulated NSR pollutant'' to GHGs regulated under this rule.

The EPA received comments supporting the adoption of this proposed language, but several commenters also expressed concern that adding this language to part 60 alone would not be sufficient. Several commenters urged the EPA to instead revise the PSD regulations in parts 51 and 52. In addition, commenters expressed concern that further steps were needed to amend the SIPs before there would be certainty that the Tailoring Rule limitations continued to apply after the adoption of CO_2 standards under CAA section 111 in this final rule.

On June 23, 2014, the United States Supreme Court, in *Utility Air Regulatory Group* v. *Environmental Protection Agency,* issued a decision addressing the application of PSD permitting requirements to GHG emissions. The Supreme Court held that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source (or modification thereof) for the purpose of PSD applicability. The Court also said that the EPA could continue to require that PSD permits, otherwise required based on emissions of pollutants other than GHGs, contain limitations on GHG emissions based on the application of BACT. The Supreme Court decision effectively upheld PSD permitting requirements for GHG emissions under Step 1 of the Tailoring Rule for ''anyway sources'' and invalidated application of PSD permitting requirements to Step 2 sources based on GHG emissions. The Court also recognized that, although the EPA had not yet done so, it could ''establish an appropriate *de minimis* threshold below which BACT is not required for a source's greenhouse gas emissions.'' 134 S. Ct. at 2449.

In accordance with the Supreme Court decision, on April 10, 2015, the U.S. Court of Appeals for the District of Columbia Circuit (the D.C. Circuit) issued an amended judgment vacating the regulations that implemented Step 2 of the Tailoring Rule, but not the regulations that implement Step 1 of the Tailoring Rule. The court specifically vacated 40 CFR 51.166(b)(48)(v) and 40 CFR 52.21(b)(49)(v) of the EPA's regulations, but did not vacate 40 CFR 51.166(b)(48)(iv) or 40 CFR 52.21(b)(48)(iv). The court also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA,* and, if so, to undertake such revisions.

The practical effect of the Supreme Court's clarification of the reach of the CAA is that it eliminates the need for Step 2 of the Tailoring Rule and subsequent steps of the GHG permitting phase in that the EPA had planned to consider under the Tailoring Rule. This also eliminates the possibility that the promulgation of GHG standards under section 111 could result in additional sources becoming subject to PSD based solely on GHGs, notwithstanding the limitations the EPA adopted in the Tailoring Rule. However, for an interim period, the EPA and the states will need to continue applying parts of the PSD definition of ''subject to regulation'' to ensure that sources obtain PSD permits meeting the requirements of the CAA.

The CAA continues to require that PSD permits issued to ''anyway sources'' satisfy the BACT requirement for GHGs. Based on the language that remains applicable under 40 CFR 51.166(b)(48)(iv) and 40 CFR 52.21(b)(49)(iv), the EPA and states may continue to limit the application of BACT to GHG emissions in those circumstances where a source emits GHGs in the amount of at least 75,000 tpy on a CO_2e basis. The EPA's intention is for this to serve as an interim approach while the EPA moves forward to propose a GHG Significant Emission Rate (SER) that would establish a *de minimis* threshold level for permitting GHG emissions under PSD. Under this forthcoming rule, the EPA intends to propose restructuring the GHG provisions in its PSD regulations so that the *de minimis* threshold for GHGs will not reside within the definition of ''subject to regulation.'' This restructuring will be designed to make the PSD regulatory provisions on GHGs universally applicable, without regard to the particular subparts of the definition of ''regulated NSR pollutant'' that may cover GHGs. Upon promulgation of this PSD rule, it will then provide a framework that states may use when updating their SIPs consistent with the Supreme Court decision.

While the PSD rulemaking described above is pending, the EPA and approved state, local, and tribal permitting authorities will still need to implement the BACT requirement for GHGs. In order to enable permitting authorities to continue applying the 75,000 tpy CO_2e threshold to determine whether BACT applies to GHG emissions from an ''anyway source'' after GHGs are subject to regulation under CAA section 111, the EPA has concluded that it continues to be appropriate to adopt the proposed language in 40 CFR 60.5515 (subpart TTTT). Because the EPA is not finalizing the proposed regulations in subparts Da and KKKK, it is not necessary to adopt the comparable provisions that the EPA proposed in 40 CFR 60.46Da(j) and 40 CFR 60.4315(b).

The EPA has evaluated 40 CFR 60.5515 in light of the Supreme Court decision and the comments received on the question of whether this CAA section 111 standard will undermine the application of the Tailoring Rule limitations. While most of the Tailoring Rule limitations are no longer needed to avoid triggering the requirement to obtain a PSD permit based on GHGs alone, the limitation in 40 CFR 51.166(b)(48)(iv) and 40 CFR 52.21(b)(49)(iv) will remain important to provide an interim applicability level for the GHG BACT requirement in ''anyway source'' PSD permits. Thus, there continues to be a need to ensure that the regulation of GHGs under CAA section 111 does not make this BACT applicability level for anyway sources effectively inoperable. The language in 40 CFR 60.5515 will continue to be effective at avoiding this result after the judicial actions described above and the adoption of this final rule. The provisions in part 60 reference 40 CFR 51.166(b)(48) and 40 CFR 52.21(b)(49) of the EPA's regulations. However, the courts have now vacated 40 CFR 51.166(b)(48)(v) and 40 CFR 52.21(b)(49)(v), and the EPA will take steps soon to eliminate these subparts from the CFR. As a result of these steps, the language of final 40 CFR 60.5515 will not incorporate the vacated parts of 40 CFR 51.166(b)(48) and 40 CFR 52.21(b)(49), but these provisions in part 60 will continue to apply to those subparts of the PSD rules that are needed on an interim basis to limit application of BACT to GHGs only when emitted by an anyway source in amounts of 75,000 tpy CO_2e or more. Thus, in this final rule, the EPA is adopting the proposed text of 40 CFR 60.5515 for this purpose without substantial change.

As to the concern expressed by some commenters that revisions to part 60 alone are not sufficient, the GHG SER rulemaking described above will include proposed revisions to the PSD regulations in parts 51 and 52 that should ultimately address this concern. The EPA acknowledges that the commenters concern will not be fully addressed for an interim period of time, but (for the reasons discussed above) the part 60 provisions adopted in this rule are sufficient to make explicit that the 75,000 tpy CO_2e BACT applicability level for GHGs will apply to GHGs that are subject to regulation under the CAA section 111 standards adopted in this rule.

Rather than adopting a temporary patch in its PSD regulations in this rule to address the implications for PSD of regulating GHGs under CAA section 111, the EPA believes it will be most efficient for the EPA and the states if the EPA completes a comprehensive PSD rule that will address all the implications of the Supreme Court decision. The revisions the EPA will consider based on the Supreme Court decision will inherently address the commenters concerns about the definition of the ''subject to regulation'' and the proposed part 60 provisions. To the extent this PSD rule is not complete before the EPA proposes additional CAA section 111 standards for GHGs, the EPA will need to consider adding provisions like 40 CFR 60.5515 to other subparts of part 60. In a separate rulemaking finalized concurrently with this rule, the EPA is also finalizing corresponding edits to 40 CFR 60.5705 in subpart UUUU to clarify that the regulated pollutant is the same for both the CAA section 111(b) and section 111(d) rules. As of this time, the EPA has not proposed GHG standards for other source categories under CAA section 111. To the extent needed, this approach of adding provisions to a few subparts in part 60 would be less burdensome to states and more efficient than revising 40 CFR 51.166 at this time solely to address the implications of regulating GHGs under CAA section 111.

The EPA understands that many commenters expressed concern that PSD SIPs would also have to be amended to address the implications of regulating GHGs under CAA section 111. However, the language in 40 CFR 60.5515 is designed to avoid the need for states to make revisions to the PSD regulations in their SIPs at this time. The EPA has previously observed that the form of each pollutant regulated under the PSD program is derived from the form of the pollutant described in regulations, such as an NSPS, that make the pollutant regulated under the CAA. 56 FR 24468, 24470 (May 30, 1991); 61 FR 9905, 9912–18 (Mar. 12, 1996); 75 FR 31522.

Moreover, it is more likely that states would need to consider a SIP revision if the EPA were to revise 40 CFR 51.166 in this rule. Revisions to 51.166 can trigger requirements for states to revise their PSD program provisions under 40 CFR 51.166(a)(6).

Given the process required in states to review their SIPs and submit them to the EPA for approval, it is most efficient for all concerned when the EPA is able to consolidate its revisions to 40 CFR 51.166. The EPA, thus, believes it will be less work for states if we issue a comprehensive set of rules addressing regulation of GHGs under the PSD program after the Supreme Court decision.

In comments on the proposed rules, states generally did not express concern that the proposed revisions to part 60 were insufficient to avoid the need for SIP revisions. In our proposal, we addressed any state with an approved PSD SIP program that applies to GHGs which believed that this final rule would require the state to revise its SIP so that the Tailoring Rule thresholds continue to apply. First, the EPA encouraged any state that considered such revisions necessary to make them as soon as possible. Second, if the state could do so promptly, the EPA said it would assess whether to proceed with a separate rulemaking action to narrow its approval of that state's SIP so as to assure that, for federal purposes, the Tailoring Rule thresholds will continue to apply as of the effective date of the final NSPS rule. 79 FR 1487. The EPA did not receive any comments or other feedback from states requesting that the EPA narrow their program to ensure the Tailoring Rule thresholds continue to apply after promulgating this rule. We do not believe such action will be necessary in any state after the Supreme Court decision and our action in this rule is to adopt the proposed part 60 provisions for purposes of ensuring the Step 1 BACT applicability level for GHGs continues to apply on an interim basis.

C. Implications for BACT Determinations Under PSD

New major stationary sources and major modifications at existing major stationary sources are required by the

CAA to, among other things, obtain a permit under the PSD program before commencing construction. The emission thresholds that define PSD applicability can be found in 40 CFR parts 51 and 52, and the PSD thresholds specific to GHGs are explained in the preceding section of this preamble.

Sources that are subject to PSD must obtain a preconstruction permit that contains emission limitations based on application of BACT for each regulated NSR pollutant. The BACT requirement is set forth in section 165(a)(4) of the CAA, and in EPA regulations under 40 CFR parts 51 and 52. These provisions require that BACT determinations be made on a case-by-case basis. CAA section 169(3) defines BACT, in general, as:

> ''an emissions limitation . . . based on the maximum degree of reduction for each pollutant . . . emitted from any proposed major stationary source or major modification which the Administrator . . . [considering energy, environmental, and economic impacts] . . . determines is achievable for such facility . . .''

Furthermore, this definition in the CAA specifies that

> ''[i]n no event shall application of [BACT] result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of the Act.''

This condition of CAA section 169(3) has historically been interpreted to mean that BACT cannot be less stringent than any applicable standard of performance under the NSPS. *See, e.g.,* U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, EPA–457/B–11–001 (March 2011) (''GHG Permitting Guidance'' or ''Guidance'') at 20–21. Thus, upon completion of an NSPS, the NSPS establishes a ''BACT Floor'' for PSD permits that are issued to affected facilities covered by the NSPS.

BACT is a case-by-case review that considers a number of factors. These factors include the availability, technical feasibility, control effectiveness, and the economic, environmental and energy impacts of the control option. See GHG Permitting Guidance at 17–46. The fact that a minimum control requirement (*i.e.,* the BACT Floor) is established by the EPA through an applicable NSPS does not bar a permitting agency from justifying a more stringent control level as BACT for a specific PSD permit.

It is important to understand how this NSPS may relate to determining BACT for new and existing EGUs that require PSD permits. PSD generally applies to major sources, while this NSPS applies to units that may be within a source. Under this NSPS, an affected facility is a new EGU or a modified or reconstructed EGU. The new source NSPS requirements apply, in general, to any stationary source that adds a new EGU that is an affected facility under this NSPS. This could, for example, include a proposed brand new (''greenfield'') power plant or an existing power plant that proposes to add a new EGU (*e.g.,* to increase its generating capacity). While this latter scenario is considered a ''new affected facility'' under the NSPS, it is generally viewed under PSD as a ''modification'' of an existing stationary source. Thus, the new source NSPS requirements could apply to a modification, as that term is defined under PSD.

In addition, this NSPS will apply to some modified and reconstructed units, as those terms are defined under part 60. Consequently, this NSPS could establish a BACT floor for existing stationary sources that are modifying an existing EGU and experience an emissions increase that makes the source subject to PSD review. However, a physical change that triggers the NSPS modification or reconstruction requirements does not necessarily subject the source to PSD requirements, and vice versa. In general, in order to trigger the NSPS modification or reconstruction requirements, a physical change must increase the maximum hourly emission rate of the pollutant (to be an NSPS modification) or the fixed capital cost of the change must exceed 50 percent of the fixed capital cost of a comparable entirely new facility (to be an NSPS reconstruction). *See* 40 CFR 60.2, 60.14, 60.15. Under the PSD program, however, a physical change (or change in the method of operation) must result in an increase in annual emissions of the pollutant by a specified emission threshold in order to be subject to PSD requirements. This emission calculation considers the unit's past annual emissions and its projected annual emissions. See, *e.g.,* 40 CFR 52.21(a)(2)(iv)(C). In addition, the PSD emissions test for a modification allows the existing source to consider qualifying emission reductions and increases at the source within a contemporaneous period to ''net out'' of, or avoid, triggering PSD review. Thus, it is important to understand the differences in how the term ''modification'' is used in the NSPS and PSD programs, and that a physical change that is a modification under one program may not necessarily be a modification under the other program.

In the preamble to the proposed NSPS for new sources, the EPA discussed whether a standard of performance for the new source NSPS, specifically the BSER for solid fuel-fired EGUs that is based on partial CCS, could become the BACT floor when permitting a modified or reconstructed EGU or non-EGU source. As noted above, BACT is a case-specific review by a permitting agency. In evaluating BACT, the permitting authority should consider all available control technologies that have the potential for practical application to the facility or emission unit under evaluation. See GHG Permitting Guidance at 24. This BACT review must include any technologies that are part of an applicable NSPS for the specific type of source and would therefore establish the minimum level of stringency for the BACT. Thus, it is possible that partial CCS could be considered in a BACT review as an available control option for a modified or reconstructed EGU facility, or for another type of source (*e.g.,* natural gas processing plant), but this NSPS is not an applicable standard to such sources so it would not establish a requirement that partial CCS is a minimum level of stringency for the BACT for those sources.

Some commenters expressed concern that, if the EPA finalizes a BSER for utility boilers and IGCC units that is based on partial CCS, it would establish a BACT Floor for new EGUs that would be inconsistent with prior BACT determinations for EGUs in both permits issued by EPA Regions and permits issued by state agencies on which the EPA has commented. Many of these comments were more directed at the development and deployment of CCS (*i.e.,* the commenter did not believe CCS should be the basis for BSER) rather than examining whether an NSPS should establish the BACT floor for applicable sources, which is the legal consequence of setting an NSPS under the terms of the CAA. Consequently, we respond to these comments in other sections of this preamble that support the selection of partial CCS as the basis for the BSER for fossil fuel-fired electric utility steam generating units.

With regard to the commenters who stated that a BSER for EGUs that is based on partial CCS would be inconsistent with BACT determinations in previous GHG PSD permits, it is important to recognize that a BACT determination is a case-by-case analysis and that technological capabilities and costs evolve over time.[551] In addition, to

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[551] In this regard, the 2011 GHG Permitting Guidance states that ''although CCS is not in widespread use at this time, EPA generally considers CCS to be an 'available' add-on pollution control technology for facilities emitting CO_2 in

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date the EPA has not issued a PSD permit with GHG BACT for a source that would be an affected facility requiring partial CCS under this NSPS (*i.e.,* a fossil fuel-fired steam generating unit), so one cannot determine whether the EPA—as a PSD permitting authority—has been either consistent or inconsistent by setting a BSER of partial CCS in this NSPS. Although, in the course of a BACT review, some permitting authorities may have determined that CCS is not technologically feasible or economically achievable for a gas-fired EGU, because of the case-by-case nature of the BACT analysis it does not automatically follow that the same conclusion is appropriate for a solid fuel-fired EGU. Furthermore, PSD permitting requirements first applied to GHGs in January 2011 and more information about GHG control technology has been gained in this four-and-a-half year period. Thus, we would expect BACT decisions to evolve as well, such that a GHG BACT review for a coal-fired EGU in 2015 may look very different from a review that was done in 2011.

Additionally, if a state agency is processing a permit application for a solid fuel-fired EGU and does not propose CCS as BACT (or does not even consider CCS as an available control for BACT), the EPA is not necessarily required to comment negatively on the draft permit, or to otherwise request or require that the state agency amend the BACT to include CCS. For state agencies that have their own EPA-approved state implementation plan, the state has primacy over their permitting actions and discretion to interpret their approved rules and to apply the applicable federal and state regulatory requirements that are in place at the time for the facility in question. The EPA's role is to provide oversight to ensure that the state operates their PSD program in accordance with the CAA and applicable rules. If the EPA does not adversely comment on a certain draft permit or BACT determination, it does not necessarily imply EPA endorsement of the proposed permit or determination.

Some commenters also felt that the determination of partial CCS as BSER is inconsistent with the agency's position on CCS in the EPA's GHG Permitting Guidance, which they say supports the notion that additional work is required before CCS can be integrated at full-scale electric utility applications. It is important to recognize that the EPA's Permitting Guidance is guidance, so it does not contain any final determination of BACT for any source. Furthermore, we disagree with the commenters' characterization of the GHG Permitting Guidance. The Guidance specifically states ‘‘[f]or the purposes of a BACT analysis for GHGs, the EPA classifies CCS as an add-on pollution control technology that is ‘‘available'' for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (*e.g.,* hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs.'' GHG Permitting Guidance at 32. As discussed elsewhere in the Guidance, technologies that should be listed in Step 1 are those that ‘‘have the potential for practical application to the emissions unit and regulated pollutant under evaluation.'' GHG Permitting Guidance at 24. The EPA continues to stand by its position on the availability of CCS in this context, as expressed in the GHG Permitting Guidance.

The GHG Permitting Guidance continues on to discuss case-specific factors and potential limitations with applying CCS, and it acknowledges that CCS may not be ultimately selected as BACT in ‘‘certain cases'' based on technology feasibility and cost. GHG Permitting Guidance at 36, 43. While acknowledging these potential challenges when it was issued in March 2011, the Guidance clearly does not rule out the selection of CCS as BACT for any source category and it is forward looking. GHG Permitting Guidance at 43 (‘‘. . . as a result of ongoing research and development, . . . CCS may become less costly and warrant greater consideration . . . in the future'') Nothing in the Guidance is inconsistent with EPA's present position that CCS is adequately demonstrated for the types of sources covered by this NSPS, as articulated elsewhere in this preamble.

A commenter asserted that the GHG Permitting Guidance should be amended because it calls for consideration of CCS in BACT determinations even though the proposed NSPS identified ‘‘partial CCS'' as BSER for new boiler and IGCC EGUs. The Guidance explains that ‘‘the purpose of Step 1 of the process is to cast a wide net and identify all control options with potential application to the emissions unit under review.'' GHG Permitting Guidance at 26. The EPA agrees that the GHG Permitting Guidance only uses the term ‘‘CCS'' and does not distinguish ‘‘partial CCS'' from ‘‘full CCS.'' But considering the purpose of Step 1 of the process, we believe that the term ‘‘CCS'', as it is used in the GHG Permitting Guidance, adequately describes the varying levels of CO_2 capture. A BACT review should analyze all available technologies in order to adequately support the BACT determination, and may require evaluation of partial CCS, full CCS, and/or no CO_2 capture. The specific facility type and CO_2 capture conditions will dictate the level(s) of CO_2 capture that are most appropriate to consider as ‘‘available'' in a BACT review.

D. Implications for Title V Program

Under the Title V program, certain stationary sources, including ‘‘major sources'' are required to obtain an operating permit. This permit includes all of the CAA requirements applicable to the source, including adequate monitoring, recordkeeping, and reporting requirements to assure sources' compliance. These permits are generally issued through EPA-approved state Title V programs.

In the January 8, 2014 proposal, the EPA discussed whether this rulemaking would impact the applicability of Title V requirements to major sources of GHGs. 79 FR 1489–90. The relevant issue for Title V purposes was, in essence, whether promulgation of CAA section 111 requirements for GHGs

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large amounts and industrial facilities with high-purity CO_2 streams.'' GHG Permitting Guidance at 35. The Guidance goes on to note that CCS may not be technically feasible at modified sources (citing possible issues with ‘‘space for CO_2 capture equipment at an existing facility''), or in other specific circumstances. Id. at 36 (‘‘Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition . . ., the need for funding . . ., timing of available transportation infrastructure, and developing a site for secure long term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard''). Id. at 42–3 EPA also noted that CCS may be expensive in individual instances and thus eliminated as a control option for that reason under step 4 of the BACT analysis, noting further that revenues from EOR may offset other costs. Id. at 42–3. See also *UARG* v. *EPA,* 134 S.Ct. 2427, 2448 (2014) (noting that EPA's GHG Permitting Guidance states that carbon capture is reasonably comparable to more traditional, end-of-stack BACT technologies, and that petitioners do not dispute that).

As explained at Section V.I.5 above, in determining that partial CCS is BSER for new fossil fuel steam electric plants, the EPA has carefully considered the issue of logistics (including cost estimates for land acquisition, transportation, and sequestration) and costs generally. Nor would new plants face the same types of constraints as modified or reconstructed sources in a BACT determination, since a new source has more leeway in choosing where to site. See text at V.G.3. above. Moreover, the GHG Permitting Guidance considered BACT determinations for all types of sources, not just those for which the EPA has determined in this rule that partial CCS is the BSER, and the concerns expressed in the Guidance thus must be considered in that broader context.

would undermine the Tailoring Rule, which, as explained above, phased in permitting requirements for GHG emissions for stationary sources under the CAA PSD and Title V permitting programs. Based on the EPA's understanding of the CAA at that time, the proposal discussed this issue in the context of the regulatory and statutory definitions of ''major source,'' focusing on revisions that had been made in the Tailoring Rule to the definitions in the Title V regulations of ''major source'' and ''subject to regulation.'' 79 FR 1489–90 (quoting 75 FR 31583). Under the Title V regulations, as revised by the Tailoring Rule, ''major source'' is defined to include, in relevant part, ''a major stationary source . . . that directly emits, or has the potential to emit, 100 tpy or more of any air pollutant subject to regulation.'' The proposal further explained that the GHG threshold that had been established in the Tailoring Rule had been incorporated into the definition of ''subject to regulation'' under 40 CFR 70.2 and 71.2, such that those definitions specify '' 'that GHGs are not subject to regulation for purposes of defining a major source, unless as of July 1, 2011, the emissions of GHGs are from a source emitting or having the potential to emit 100,000 tpy of GHGs on a CO_2e basis.' '' *Id.* (quoting 75 FR 31583). The proposal thus concluded that the Title V definition of ''major source,'' as revised by the Tailoring Rule, did not on its face distinguish among types of regulatory triggers for Title V. It further noted that the Title V program had already been triggered for GHGs, and thus concluded that the promulgation of CAA section 111 requirements would not further impact Title V applicability requirements for major sources of GHGs. 79 FR 1489–90.

As noted elsewhere in this section, after the proposal for this rulemaking was published, the United States Supreme Court issued its opinion in *UARG* v. *EPA,* 134 S.Ct. 2427 (June 23, 2014), and in accordance with that decision, the D.C. Circuit subsequently issued an amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* Nos. 09–1322, 10–073, 10–1092 and 10–1167 (D.C. Cir., April 10, 2015). Those decisions support the same overall conclusion as the EPA discussed in the proposal, though for different reasons.

With respect to Title V, the Supreme Court said in *UARG* v. *EPA* that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a Title V operating permit. In accordance with that decision, the D.C. Circuit's amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* vacated the Title V regulations under review in that case to the extent that they require a stationary source to obtain a Title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA,* and, if so, to undertake to make such revisions. These court decisions make clear that promulgation of CAA section 111 requirements for GHGs will not result in the EPA imposing a requirement that stationary sources obtain a Title V permit solely because such sources emit or have the potential to emit GHGs above the applicable major source thresholds.[552]

To be clear, however, unless exempted by the Administrator through regulation under CAA section 502(a), any source, including an area source (a ''non-major source''), subject to an NSPS is required to apply for, and operate pursuant to, a Title V permit that assures compliance with all applicable CAA requirements for the source, including any GHG-related applicable requirements. This aspect of the Title V program is not affected by *UARG* v. *EPA,* as the EPA does not read that decision to affect either the grounds other than those described above on which a Title V permit may be required or the applicable requirements that must be addressed in Title V permits.[553] Consistent with the proposal, the EPA has concluded that this rule will not affect non-major sources and there is no need to consider whether to exempt non-major sources. Thus, sources that are subject to the CAA section 111 standards promulgated in this rule are required to apply for, and operate pursuant to, a Title V permit that assures compliance with all applicable CAA requirements, including any GHG-related applicable requirements.

E. Implications for Title V Fee Requirements for GHGs

1. Why is the EPA revising Title V fee rules as part of this action?

The January 8, 2014 notice of proposed rulemaking (79 FR 1430) (the ''EGU GHG NSPS proposal'' or ''NSPS proposal'') proposed the first section 111 standards to regulate GHGs at EGUs. That notice also included proposed revisions to the fee requirements of the 40 CFR part 70 and part 71 operating permit rules under Title V of the CAA to avoid inadvertent consequences for fees that would be triggered by the promulgation of the first CAA section 111 standard to regulate GHGs. If we do not revise the fee rules by the time of the promulgation of the NSPS standards for GHGs, then approved part 70 programs implemented by state, local and tribal permitting authorities[554] that rely on the ''presumptive minimum'' approach and the part 71 program implemented by the EPA would be required to account for GHGs in emissions-based fee calculations at the same dollar per ton ($/ton) rate as other air pollutants. The EPA believes this would result in the collection of fees in excess of what is required to cover the reasonable costs of an operating permit program. See NSPS proposal 79 FR 1490.

In response to these concerns, the EPA proposed regulatory changes to limit the fees collected based on GHG emissions and proposed two fee adjustment options to increase the fees collected based on the costs for permitting authorities to conduct certain review activities related to GHG emissions, while still providing sufficient funding for an operating permit program. Also, we proposed an option that would have provided for no fee adjustments to recover the costs of conducting review activities related to GHG emissions. *Id.* 79 FR 1490. The EPA did not propose any action related to state and local permitting authorities that do not use the presumptive minimum approach.

Most commenters on the proposal, including state and local permitting authorities, were supportive of exempting GHGs from the emissions-based fee calculations of the permit

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[552] As explained elsewhere in this notice, the EPA intends to conduct future rulemaking action to make the appropriate revisions to the operating permit rules to respond to the Supreme Court decision and the D.C. Circuit's amended judgment. To the extent there are any issues related to the potential interaction between the promulgation of CAA section 111 requirements for GHGs and Title V applicability based on emissions above major source thresholds, the EPA expects there would be an opportunity to consider those during that rulemaking.

[553] See Memorandum from Janet G. McCabe, Acting Assistant Administrator, Office of Air and Radiation, and Cynthia Giles, Assistant Administrator, Office of Enforcement and Compliance Assurance, to Regional Administrators, Regions 1–10, *Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in Utility Regulatory Group* v. *Environmental Protection Agency* (July 24, 2014) at 5.

[554] Hereafter, for the sake of simplicity, we will generally refer to part 70 permitting authorities as ''state'' permitting authorities and refer to part 70 programs as ''state'' programs.

rules, but support for the fee adjustment options was mixed, with state and local permitting authorities generally supporting either of the two fee adjustments, and other commenters generally supporting the option that provides for no fee adjustment.

2. Background on the Fee Requirements of Title V

In the NSPS proposal, the EPA explained the statutory and regulatory background related to the requirement that permitting authorities collect fees from the owner or operator of Title V sources that are sufficient to cover the costs of the operating permit program. CAA section 502(b)(3)(A) requires an operating permit program to include a requirement that sources ''pay an annual fee, or the equivalent over some other period, sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the permit program.'' See also 40 CFR 70.9(a). CAA section 502(b)(3)(B)(i) requires that, in order to have an approvable operating permit program, the permitting authority must show that ''the program will result in the collection, in the aggregate, from all sources [required to get an operating permit]'' of either ''an amount not less than $25 per ton of each regulated pollutant [adjusted annually for changes in the consumer price index], or such other amount as the Administrator may determine adequately reflects the reasonable costs of the permit program.'' See also 40 CFR 70.9(b)(2). This has been generally referred to as the ''presumptive minimum'' approach. If a permitting authority does not wish to use the presumptive minimum approach, it may demonstrate ''that collecting an amount less than the [presumptive minimum amount] will'' result in the collection of funds sufficient to cover the costs of the program. CAA section 503(b)(3)(B)(iv); see also 40 CFR 70.9(b)(5). This has been generally referred to as the ''detailed accounting'' approach. CAA section 502(b)(3)(B)(ii) sets forth a definition of ''regulated pollutant'' for purposes of calculating the presumptive minimum that includes each pollutant regulated under section 111 of the CAA. See also 40 CFR 70.2.

3. What fee rules did we propose to revise?

In the NSPS proposal, to exempt GHGs from emissions-based fee calculations, we proposed to exempt GHGs from the definition of ''regulated pollutant'' for purposes of operating permit fee calculations (''the GHG exemption''). The EPA then proposed two alternative ways to account for the costs of addressing GHGs in operating permits through a cost adjustment. First, we proposed a modest additional cost for each GHG-related activity of certain types that a permitting authority would process (''the GHG adjustment option 1''). Alternatively, we proposed a modest additional increase in the per ton rate used in the presumptive minimum calculation for all non-GHG fee pollutants (''the GHG adjustment option 2''). The EPA also solicited comment on an option that would provide no additional cost adjustment to account for GHGs (''the GHG adjustment option 3''). All of the GHG adjustment options are based on the assumption that the GHG exemption is finalized. See NSPS Proposal 79 FR 1493–1495.

The EPA additionally proposed two clarifications. The first was regulatory text in 40 CFR part 60, subparts Da, KKKK, and TTTT, to clarify that GHGs, as opposed to CO_2, is the regulated pollutant for fee purposes (''the fee pollutant clarification''). *Id.* at 1505, 1506 and 1511. The second was a proposal to move the existing definition of ''Greenhouse gases (GHGs)'' within 40 CFR 70.2 and 71.2 to promote clarity in the regulations (''the GHG clarification''). *Id.* 79 FR 1490, 1517, 1518.

For background purposes, below is a brief summary of each of the proposals.

a. The GHG Exemption

To address the fee issues discussed in the NSPS proposal, the EPA proposed to exempt GHG emissions from the definition of ''regulated pollutant (for presumptive fee calculation)'' in 40 CFR 70.2 and the definition of ''regulated pollutant (for fee calculation)'' in 40 CFR 71.2.[555] See NSPS preamble 79 FR 1493, 1495.

b. The GHG Adjustment Option 1

The first proposed ''GHG adjustment'' option (option 1) was to include an additional cost for each GHG-related activity of certain types that a permitting authority would process (an activity-based adjustment). The three activities identified for this option were ''GHG completeness determination (for initial permit or for updated application)'' at 43 hours of burden,[556] ''GHG evaluation for a modification or related permit action'' at 7 hours of burden, and ''GHG evaluation at permit renewal'' at 10 hours of burden. See also 79 FR 1494, fn. 280 (providing a description of each of these activities).

For part 70, the burden hours per activity would be multiplied by the cost of staff time (in $/hour) specific to the state, including wages, benefits, and overhead, to determine the cost of each activity. All the activities for a given period would be totaled to determine the total GHG adjustment for the state. See 79 FR 1494.

For part 71, we proposed a labor rate assumption of $52 per hour in 2011 dollars. Using that labor rate, we proposed to determine the GHG fee adjustment for each GHG permitting program activity to be a specific dollar amount for each activity (''set fees'') that the source would pay for each activity performed. See 79 FR 1495. The EPA proposed to revise 40 CFR 70.9(b)(2)(v) and 40 CFR 71.9(c)(8) to implement this option.

c. The GHG Adjustment Option 2

The second proposed GHG adjustment option (option 2) was to increase the dollar per ton ($/ton) rates used in the fee calculations for each non-GHG fee pollutant. The revised $/ton rates would be multiplied by the total tons of non-GHG fee pollutants actually emitted by any source to determine the applicable total fees. The EPA proposed to increase the $/ton rates by 7 percent.[557] See NSPS proposal 79 FR 1494, 1495.

d. The GHG Adjustment Option 3

The EPA also solicited comment on not charging any fees related to GHGs (option 3). The basis for this proposed option was the observation that most sources that need to address GHGs in a permit would also emit non-GHG fee pollutants, and thus, the cost of permitting for any particular source may be accounted for adequately without charging any additional fees related to GHGs. *Id.* 79 FR 1494–1495.

e. The Fee Pollutant Clarification

Another fee-related proposal was to add regulatory text to 40 CFR part 60, subparts Da, KKKK, and TTTT, to clarify that the fee pollutant for operating permit purposes would be considered to be ''GHGs,'' (as defined in

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[555] Hereafter we will refer to these definitions as the ''fee pollutant'' definitions. Also, note that both fee pollutant definitions cross-reference the definitions of ''regulated air pollutant'' which includes air pollutants ''subject to any standard promulgated under section 111 of the Act.''

[556] Burden is the hours of staff time necessary to perform a task.

[557] The EPA estimated that both options 1 and 2 would result in about a 7 percent increase in the fees collected by operating permit programs affected by the proposed rule. For example, the presumptive minimum fee rate in effect for September 1, 2014 through August 31, 2015 is $48.27/ton. A 7 percent increase under option 2 would result in a revised fee of $51.65/ton.

40 CFR 70.2 and 71.2),[558] rather than solely CO_2, which would be regulated under the section 111 standards and implemented through the EGU GHG NSPS. *Id.* 79 FR 1505, 1506, and 1511.

f. The GHG Clarification

The EPA proposed to move the existing definition of ''Greenhouse gases (GHGs)'' within the definition of ''Subject to regulation'' in 40 CFR 70.2 and 71.2 to a separate definition within those sections to promote clarity in the regulations. *Id.* 79 FR 1490, 1517, 1518.

4. What action is the EPA finalizing?

In this action, the EPA is finalizing the following elements as proposed: (1) The GHG exemption, (2) the GHG adjustment option 1, and (3) the fee pollutant clarification.

Public commenters on the proposal stated both support and opposition to using the NSPS rulemaking action to revise the Title V fee rules. Two commenters stated that proposing the Title V fee revisions within the NSPS rulemaking would result in fewer commenters, particularly state and local permitting authorities, having knowledge of the changes to the fee rules and sufficient opportunity to comment on the changes because the NSPS proposal is limited to a single source category, and one stated that a separate proposal for the fee rules would provide a sufficient opportunity for public comment. The EPA believes it is appropriate to move forward with final action amending the Title V fee regulations as part of this NSPS. As we explained in the preamble for the proposal and elsewhere in this final rule, the fee rules and the section 111 standards are interrelated because, if we do not revise the fee rules, promulgation of the final NSPS will trigger certain requirements related to Title V fees for GHG emissions that the EPA believes will result in the collection of excessive fees in states that implement the presumptive minimum approach and in the part 71 program. Thus, it is important to finalize the revisions to the fee rules at the same time or prior to this NSPS, and it is within the EPA's discretion to address the NSPS and the fee rules at the same time as part of the same rulemaking action. In response to the commenters who were concerned that including the fee rule proposal as part of the NSPS proposal would result in the public not having sufficient public comment opportunities, the EPA believes sufficient public comment opportunities were provided on the fee rule changes because the proposal met all public participation requirements and we provided additional public outreach, including to state and local permitting authorities, which discussed the fee rule proposal. In addition to the publication of the proposed rulemaking in the **Federal Register**, the EPA held numerous hearings, reached out to state partners and the public, and developed numerous fact sheets and other information to support public comment on this rule. The EPA has complied with the applicable public participation requirements and executive orders. The proposal met all the requirements for public notice—it contained a clear and detailed explanation of how the part 70 and 71 rules would be affected by the promulgation of the CAA section 111 standard for EGUs and how the EPA proposed to revise the related regulatory provisions. We received many comments on the proposal to revise the fee rule for operating permits programs, and we are taking those comments into consideration in the finalization of the rulemaking action.

a. The GHG Exemption

The EPA is taking final action to revise the definition of regulated pollutant (for presumptive fee calculation) in 40 CFR 70.2 and regulated pollutant (for fee calculation) in 40 CFR 71.2 to exempt GHG emissions. This regulatory amendment will have the effect of excluding GHG emissions from being subject to the statutory ($/ton) fee rate set for the presumptive minimum calculation requirement of part 70 and the fee calculation requirements of part 71. We received supportive comments from the majority of public commenters, including state and local permitting authorities and others, on revising the operating permit rules to exempt GHGs from the emission-based calculations that use the statutory fee rates. We are finalizing this portion of the proposal for the same reasons we explained in the proposal notice, including that leaving these regulations unchanged would have resulted in the collection of fee revenue far beyond the reasonable costs of an operating permit program. The EPA believes that these revisions (in conjunction with the GHG adjustment, see below) are consistent with the CAA requirements for fees pursuant to the authority of section 502(b)(3)(B)(i).

Some members of the public opposed the proposed GHG exemption for reasons including that it may limit permitting authorities' ability to charge sufficient fees to cover the cost of GHG permitting[559] if the state is barred from exceeding minimum requirements set by the EPA. Despite this adverse comment, the EPA believes it is appropriate to finalize the GHG exemption because we are not finalizing any requirements that would require states to charge any particular fees to any particular sources. The changes we are finalizing to part 70 concern the presumptive minimum approach, which sets a minimum fee target for states that have decided to follow the presumptive minimum approach. Neither the statute nor the final rule require any state following the presumptive minimum approach (or any other approach) to charge fees to sources using any particular method. Thus, the GHG exemption will not limit states' ability to structure their individual fee programs however they see fit in order to meet the requirement that they collect revenue sufficient to cover all reasonable costs of their permitting program. See CAA section 502(b)(3); 40 CFR 70.9(b)(3).

b. The GHG Adjustment Option 1

The EPA is finalizing GHG adjustment option 1 because we believe it will result in a system for the calculation of costs for part 70 and fees for part 71 that is most directly related to the costs of GHG permitting. The EPA has determined that some adjustment to cost and fee accounting is important because the recent addition of GHG emissions to the operating permitting program does add new burdens for permitting authorities. Although GHG adjustment option 3 (no GHG permitting fee adjustments) was supported by many industrial commenters, the EPA rejected it because it is in tension with the statutory requirement that permitting authorities collect sufficient fees to cover all the reasonable costs of permitting. See CAA section 502(b)(3)(A). Some state and local permitting authorities provided comments supporting option 1, while others supported option 2, and some supported either option, stating no preference. Also, a few state and local permitting authorities supported finalizing no adjustment and a few others asked for flexibility to set fee adjustments not proposed by the EPA, but that they believed would be appropriate for their program.

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[558] Note that in 40 CFR 70.2 and 71.2, the term ''Greenhouse gases (GHGs)'' is defined as the ''aggregate group of six greenhouse gases: Carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.''

[559] We use the term ''GHG permitting'' in this section of the notice to refer to measures undertaken by permitting authorities to ensure that GHGs and any applicable requirements related to GHGs are appropriately addressed in Title V permitting.

The EPA is finalizing option 1 instead of option 2 because the option 1 adjustments are based on the actual costs for permitting authorities to process specific actions that require GHG reviews. The option 2 approach, which would have added a 7 percent surcharge to the $/ton rate used in the fee-related calculations, may have been administratively easier to implement, but is tied to the emissions of non-GHG air pollutants, which are not directly related to the costs of GHG permitting.

Consistent with CAA section 502(b)(3)(B)(i), the Administrator has determined that the final rule's approach of exempting GHG emissions from fee-related calculations and accounting for the GHG permitting costs through option 1 will result in fees that will cover the reasonable costs of the permitting programs.

The EPA is revising the part 70 regulations through this final action, specifically 40 CFR 70.9(b)(2), to modify the presumptive minimum approach to add the activity-based cost of GHG permitting activities, outlined in the revised 40 CFR 70.9(b)(2)(v), to the emissions-based calculation of 40 CFR 70.9(b)(2)(i), which is being revised to now exclude GHG emissions. To determine the activity-based GHG adjustment under 40 CFR 70.9(b)(2)(v), the permitting authority will multiply the burden hours for each activity (set forth in the regulation) by the cost of staff time (in $ per hour), including wages, benefits, and overhead, as determined by the state, for the particular activities undertaken during the particular time period.

States that implement the presumptive minimum approach will need to follow the final rule's option 1 approach.[560] States that use the detailed accounting approach are not directly affected by this rulemaking, but they must ensure that their fee collection programs are sufficient to fully fund all reasonable costs of the operating permit program, including costs attributable to GHG-related permitting. The EPA suggests states that use the detailed accounting approach consider the 7 percent assumption for the costs of GHG permitting in any such analysis, consistent with the EPA analysis of options 1 and 2 in the proposal.

Consistent with 40 CFR 70.4(i), a state that wishes to change its operating permit program as a result of this final rule must apprise the EPA. The EPA will review the materials submitted concerning the change and decide if a formal program revision process is needed and will inform the state of next steps. The communication apprising the EPA of any such changes should include at least a narrative description of the change and any other information that will assist the EPA in its assessment of the significance of the changes. Certain changes, such as switching from the presumptive minimum method to a detailed accounting method, will be considered substantial program revisions and be subject to the requirements of 40 CFR 70.4(i)(2).

With respect to the part 71 program, in this final action the EPA is revising 40 CFR 71.9(c) to require each part 71 source to pay an annual fee which is the sum of the activity-based fee of 40 CFR 71.9(c)(8) and the emissions-based fee of 40 CFR 71.9(c)(1)–(4),[561] which excludes GHG emissions. To determine the activity-based fee, the revised 40 CFR 71.9(c)(8) requires the source to pay a ''set fee'' for each listed activity that has been initiated since the fee was last paid. Under part 71, fees are typically paid at the time of initial application submittal, and thereafter, annually on the anniversary of the initial fee payment, or on any other dates that may be established in the permit. These set fees would not change until such time as we may revise our part 71 rule to change the set fees.

The final rule implements the option 1 approach by listing three activities performed by permitting authorities that involve GHG reviews. The following describes the activities as described in our proposal and certain clarifications we are making in the final rule to ensure consistent implementation.

The EPA is finalizing that the first listed activity under option 1 is ''GHG completeness determination (for initial permit or updated application).'' This activity must be counted for each new initial permit application, even for applications that do not include GHGs emissions or applicable requirements, since an important part of any completeness determination will be to determine that GHG emissions and applicable requirements have been properly addressed, as needed, in the application. The fee for this activity is a one-time charge that covers the initial application and any supplements or updates. The EPA believes that a single charge for a GHG completeness determination will be adequate to cover the reasonable costs for a permitting authority to review an initial application and any subsequent application updates related to initial permit issuance; thus, any updates to an initial application are included in a single ''GHG completeness determination,'' rather than as a separate activity for which the source would be charged in addition to the completeness determination for the initial application. This is an important distinction because many sources submit multiple permit application updates, either voluntarily or as required by the permitting authority, during application review, many of which do not require a separate or comprehensive completeness determination.

The EPA is finalizing regulatory text that would describe the second listed activity as ''GHG evaluation for a permit modification or related permit action.''[562] The EPA had proposed that the second listed activity under option 1 would be ''GHG evaluation for a modification or related permit action.'' For the final rule, we are clarifying that we are adding a cost for a ''permit modification'' rather than for a ''modification.'' The term ''modification'' may be interpreted to refer to any change at a source, even a change that would not be required to be processed as a ''permit modification,'' while ''permit modification'' refers to any revision to an operating permit that cannot be processed as an administrative permit amendment and thus requires a review by a permitting authority as either a significant or minor permit modification.

The EPA is finalizing the third activity as ''GHG evaluation at permit renewal.'' This activity covers the processing of all permit renewal applications and will involve evaluations of whether any GHG applicable requirements are properly included.

Some members of the public commented that finalizing a GHG adjustment would inappropriately

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[560] A presumptive minimum state may require various changes to its approved operating permit program before it may begin to implement the option 1 approach. For example, its regulations, and/or program procedures and practices, may need to be revised, depending on the structure of the fee provisions in the state's program; thus, the exact response necessary to address this final action may vary from state to state.

[561] Note that the emissions-based fee calculation differs somewhat depending on whether the part 71 program is being implemented by the EPA (see 40 CFR 71.9(c)(1)); a state, local or tribal agency with delegated authority from the EPA (see § 71.9(c)(2)); the EPA with contractor assistance (see § 71.9(c)(3)); or an agency with partial delegation authority (see § 71.9(c)(4)).

[562] The EPA notes that the term ''permit modification'' in this context refers to all significant permit modifications and minor permit modifications under operating permit rules, but not to ''administrative permit amendments,'' as such amendments are not defined as ''permit modifications'' in the permit rules. See, *e.g.,* 40 CFR 70.7(d), (e), and (f).

increase sources' financial burdens. The EPA has explained, both in the proposal notice and elsewhere in this preamble, the importance of the fee-related revisions to account for the costs associated with GHG-related permitting. The EPA believes that the revisions being finalized will result in modest and reasonable fee increases necessary to cover states' increased costs.[563] To the extent that commenters intended to argue that the adjustments we proposed would exceed the actual costs of GHG permitting, no commenters provided any information or analysis to support that position. Some commenters did state that the costs associated with GHG-related permitting should be minimal because few applicable requirements will apply to GHGs. As stated earlier in this notice, the EPA's cost estimate for the proposal concerned the incremental costs of GHG permitting for any source, not just those that would have, at the time of the analysis, triggered the requirement to get a permit based on GHG emissions or applicable requirements.

Despite some comments received to the contrary, the EPA does not believe it is appropriate to delay the finalization of the GHG adjustment. The EPA does not believe such delays would be consistent with CAA section 502(b)(3)(A) because states have been incurring costs attributable to GHG permitting for several years now and increased fees must be collected to cover the increased costs. The regulatory changes being finalized in this action provide the states with optimal flexibility and sufficient funding to implement their GHG permitting programs. Some commenters had specifically stated that the EPA should delay finalization of this rule until the completion of the next ICR renewal process. While we do not believe delaying this rule is appropriate, as explained above, the EPA notes that we remain committed to collecting and analyzing additional data on costs attributable to GHG permitting for operating permit programs. We may adjust the GHG cost adjustments in future rulemakings if necessary to comply with the requirements of the Act.

As an alternative to the options proposed by the EPA, some commenters asserted that the EPA should make a GHG cost adjustment using a separate, but reduced fee rate ($/ton) for GHGs. We, however, believe that the option 1 approach of the final rule will be more equitable for sources and more representative of actual costs because option 1 considers the costs of the actual permitting activities performed by a particular permitting authority, while any emissions-based approach would not be as directly related to actual costs incurred by permitting authorities.

Some commenters alleged that the EPA's proposal on adjustments to the operating permit programs was vague. The EPA provided a thorough discussion of our rationale in the proposal, including the basis for the GHG adjustments, and we proposed regulatory text to implement our proposal. We explained in the proposal that support for the cost adjustment for GHGs under option 1 is contained in several analyses performed by the EPA and approved by the OMB related to the effect of the addressing GHG requirements in operating permits. These analyses have been placed in the docket for this rulemaking. The analyses include: The Regulatory Impact Assessment (RIA) for the Tailoring Rule (see Regulatory Impact Analysis for the Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Final Report, May 2010); the part 70 ICR change request for the Tailoring Rule (which was based on the RIA for the Tailoring Rule); and the current ICR for part 70 (EPA ICR number 1587.12; OMB control number 2060–0243).

Several commenters asked that we make changes to the option 1 approach that we proposed, such as adding new activities or decreasing the costs we assumed for the proposal. In response to these comments, we note that we received no quantitative data or other information from commenters that we believe demonstrates the need to revise the list of activities we included under option 1 or the burden hour assumptions under option 1 for the activities. Note that to promote consistent implementation of the final option 1 approach, the preamble describes elsewhere a few clarifications concerning the activities under option 1 and one minor revision to the regulatory text of one of the activities.

Since the EPA's proposed rulemaking, the Supreme Court decided in *UARG* v. *EPA* that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a Title V operating permit.[564] The EPA's review of the effect of the Supreme Court decision on the burden hour assumptions for the GHG review activities under proposed option 1 is that the effects are not significant enough to warrant revision of the burden hour assumptions in the final rule. Proposed option 1 was based on the assumption that permitting authorities would need to evaluate all permit applications for initial permit issuance, significant and minor permit modifications, and permit renewals for GHG issues (even if there are no applicable GHG requirements). Even after the *UARG* v. *EPA* decision, permitting authorities will continue to need to evaluate GHG issues for sources applying for a title V permit and for permit modifications and renewals for existing permits, and we do not anticipate that the decision will significantly affect the total number of such evaluations that will occur in any given year compared to the assumptions in our analysis, which as explained above, were based on the incremental costs of GHG permitting for any source. Thus, we are finalizing the burden hour assumptions as they were proposed. See NSPS proposal at 1494 and the supporting statement for the 2012 part 70 ICR renewal. Also, as discussed previously, we remain committed to collecting and analyzing additional data on costs and we may adjust the burden hour assumptions or other aspects of option 1 in a future rulemaking, if needed.

c. The Fee Pollutant Clarification

We are also finalizing the proposed addition of text within 40 CFR part 60, subpart TTTT, to clarify that the fee pollutant for operating permit purposes is GHG (as defined in 40 CFR 70.2 and 71.2). We are finalizing these provisions to add clarity to our regulations and to avoid the potential need for possible future rulemakings to adjust the title V fee regulations if any constituent of GHG, other than CO_2, becomes subject to regulation under section 111 for the first time. The proposal was to add this clarifying text to 40 CFR part 60, subparts Da, KKKK, and TTTT. The final rule adds the clarification text only to subpart TTTT because the EPA is

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[563] The EPA estimated in the proposal that option 1 would result in about a 7 percent overall increase in the annual part 70 fees that are collected by all permitting authorities nationally. See 79 FR 1494.

[564] The EPA does not, however, read the *UARG* decision to affect other grounds on which a Title V permit may be required or the applicable requirements that must be addressed in Title V permits. *See* Memorandum from Janet G. McCabe, Acting Assistant Administrator, Office of Air and Radiation, and Cynthia Giles, Assistant Administrator, Office of Enforcement and Compliance Assurance, to Regional Administrators, Regions 1–10, *Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in Utility Regulatory Group* v. *Environmental Protection Agency* (July 24, 2014) at 5.

codifying all of the requirements for the affected EGUs in a new subpart TTTT and including all CO_2 emission standards for the affected EGUs (electric utility steam generating units, as well as natural gas-fired stationary combustion turbines) in that newly created subpart. See Section III.B of this preamble for more on this subject.

d. The GHG Clarification

The EPA is taking no action at this time on the proposal to move the definitions of ''Greenhouse gases (GHG)'' within the definition of ''Subject to regulation'' in 40 CFR parts 70 and 71. No public comments were received on this proposed clarification; however, subsequent to the proposal, on June 23, 2014, the Supreme Court in *UARG* v. *EPA* decided that GHG emissions could not be used in making certain applicability determinations under the operating permit rules. More specifically with respect to title V, as described above, the Supreme Court said that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a title V operating permit. In accordance with the Supreme Court decision, on April 10, 2015, the D.C. Circuit issued an amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* Nos. 09–1322, 10–073, 10–1092 and 10–1167 (D.C. Cir. April 10, 2015), which, among other things, vacated the title V regulations under review in that case to the extent that they require a stationary source to obtain a title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA,* and, if so, to undertake to make such revisions.

In response to the Supreme Court decision and the D.C. Circuit's amended judgment, the EPA intends to conduct future rulemaking action to make the appropriate revisions to the operating permit rules. As part of any such future rulemaking action, the EPA may consider finalizing the proposal to move the definitions of GHGs within the operating permit rules.

F. Interactions With Other EPA Rules

Fossil fuel-fired EGUs are, or potentially will be, impacted by several other recently finalized or proposed EPA rules.[565] Many of the rules that impact fossil fuel-fired EGUs apply to existing facilities as well as newly constructed, modified, or reconstructed facilities. In fact, the rules described below are more applicable to existing EGUs than to newly constructed, modified, or reconstructed EGUs. Although those rules will affect EGUs as existing sources, because we expect that there will be few NSPS modifications or reconstructions, we don't anticipate those rules affecting EGUs as modified or reconstructed sources. In constructing new EGUs, sources can take all applicable requirements of the various rules into consideration.

1. Mercury and Air Toxics Standards (MATS)

On February 16, 2012, the EPA issued the MATS rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. The MATS rule will reduce emissions of heavy metals, including mercury (Hg), arsenic (As), chromium (Cr), and nickel (Ni); and acid gases, including hydrochloric acid (HCl) and hydrofluoric acid (HF). These toxic air pollutants, also known as hazardous air pollutants or air toxics, are known to cause, or suspected of causing, damage nervous system damage, cancer, and other serious health effects. The MATS rule will also reduce SO_2 and fine particle pollution, which will reduce particle concentrations in the air and prevent thousands of premature deaths and tens of thousands of heart attacks, bronchitis cases and asthma episodes.

New or reconstructed EGUs (*i.e.,* sources that commence construction or reconstruction after May 3, 2011) subject to the MATS rule are required to comply by April 16, 2012 or upon startup, whichever is later.

Existing sources subject to the MATS rule were required to begin meeting the rule's requirements on April 16, 2015. Controls that will achieve the MATS performance standards are being installed on many units. Certain units, especially those that operate infrequently, may be considered not worth investing in given today's electricity market, and are closing. The final MATS rule provided a foundation on which states and other permitting authorities could rely in granting an additional, fourth year for compliance provided for by the CAA. States report that these fourth year extensions are being granted. In addition, the EPA issued an enforcement policy that provides a clear pathway for reliability-critical units to receive an administrative order that includes a compliance schedule of up to an additional year, if it is needed to ensure electricity reliability.[566]

2. Cross-State Air Pollution Rule (CSAPR)

The CSAPR requires states to take action to improve air quality by reducing SO_2 and NO_X emissions that cross state lines. These pollutants react in the atmosphere to form fine particles and ground-level ozone and are transported long distances, making it difficult for other states to attain and maintain the NAAQS. The first phase of CSAPR became effective on January 1, 2015, for SO_2 and annual NO_X, and May 1, 2015, for ozone season NO_X. The second phase will become effective on January 1, 2017, for SO_2 and annual NO_X, and May 1, 2017, for ozone season NO_X. Many of the power plants participating in CSAPR have taken actions to reduce hazardous air pollutants for MATS compliance that will also reduce SO_2 and/or NO_X. In this way these two rules are complementary. Compliance with one helps facilities comply with the other.

3. Requirements for Cooling Water Intake Structures at Power Plants (316(b) Rule)

On May 19, 2014, the EPA issued a final rule under section 316(b) of the Clean Water Act (33 U.S. Code section 1326(b)) (referred to hereinafter as the 316(b) rule.) The rule was published on August 15, 2014 (79 FR 48300; August 15, 2014), and became effective October 14, 2014. The 316(b) rule establishes new standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities.[567] The 316(b)

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[565] We discuss other rulemakings solely for background purposes. The effort to coordinate rulemakings is not a defense to a violation of the CAA. Sources cannot defer compliance with existing requirements because of other upcoming regulations.

[566] Following promulgation of the MATS rule, industry, states and environmental organizations challenged many aspects of the EPA's threshold determination that regulation of EGUs is ''appropriate and necessary'' and the final standards regulating hazardous air pollutants from EGUs. The U.S. Court of Appeals for the D.C. Circuit upheld all aspects of the MATS rule. *White Stallion Energy Center* v. *EPA,* 748 F.3d 1222 (D.C. Cir. 2014). The decision was unanimous on all issues except a dissent was filed because the EPA did not consider cost when determining regulation of EGUs is appropriate. In *Michigan* v. *EPA,* case no. 14–46, the Supreme Court reversed the D.C. Circuit decision upholding the MATS rule finding that EPA erred by not considering cost when determining that regulation of EGUs was ''appropriate'' pursuant to section 112(n)(1). The Supreme Court considered only the narrow question of cost and did not review the other holdings of the D.C. Circuit, nor did the Supreme Court vacate the MATS rule.

[567] CWA section 316(b) provides that standards applicable to point sources under sections 301 and

rule subjects existing power plants and manufacturing facilities that withdraw in excess of 2 million gallons per day (MGD) of cooling water, and use at least 25 percent of that water for cooling purposes, to a national standard designed to reduce the number of fish destroyed through impingement and entrainment. Existing sources subject to the 316(b) rule are required to comply with the impingement requirements as soon as practicable after the entrainment requirements are determined. They must comply with applicable site-specific entrainment reduction controls based on the schedule of requirements established by the permitting authority. Additional information regarding the 316(b) rule for existing sources is included in Section IX.C of the preamble to the CAA section 111(d) emission guidelines for existing EGUs that the EPA is finalizing simultaneously with this rule. Although the recently issued 316(b) rule discussed here applies to existing sources, there are also 316(b) technology-based standards for new sources with cooling water intake structures.

4. Disposal of Coal Combustion Residuals From Electric Utilities (CCR Rule)

On December 19, 2014, the EPA issued the final rule for the disposal of coal combustion residuals from electric utilities. The rule provides a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCRs), commonly known as coal ash, from coal-fired power plants. The CCR rule establishes technical requirements for existing and new CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA), the nation's primary law for regulating solid waste. New CCR landfills and surface impoundments are required to meet the technical criteria before any CCR is placed into the unit. Existing CCR surface impoundments and landfills are subject to implementation timeframes established in the rule for the individual technical criteria. For additional information regarding the CCR rule, see Section IX.C of the preamble to the CAA section 111(d) emission guidelines for existing EGUs that the EPA is finalizing along with this rule.

5. Steam Electric Effluent Limitation Guidelines and Standards (SE ELG Rule)

The EPA is reviewing public comments and working to finalize the proposed SE ELG rule which will impact fossil fuel-fired EGUs. In 2013, the EPA proposed the SE ELG rule (78 FR 34432; June 7, 2013) to strengthen the controls on discharges from certain steam electric power plants by revising technology-based effluent limitations guidelines and standards for the steam electric power generating point source category. The proposed regulation, which includes new requirements for both existing and new generating units, would reduce impacts to human health and the environment by reducing the amount of toxic metals and other pollutants currently discharged to surface waters from power plants. The EPA intends to take final action on the proposed rule by September 30, 2015. Section IX.C of the preamble to the CAA section 111(d) emission guidelines for existing EGUs that the EPA is finalizing simultaneously with this rule includes additional information regarding the SE ELG rule.

The EPA recognizes the importance of assuring that each of the rules described above can achieve its intended environmental objectives in a commonsense, cost-effective manner, consistent with underlying statutory requirements, and while assuring a reliable power system. Executive Order (E.O.) 13563, ''Improving Regulation and Regulatory Review,'' issued on January 18, 2011, states that ''[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote . . . coordination, simplification, and harmonization.'' E.O. 13563 further states that ''[e]ach agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation.'' Within the EPA, we are paying careful attention to the interrelatedness and potential impacts on the industry, reliability and cost that these various rulemakings can have.

As discussed in earlier sections of this preamble, the EPA has identified potential alternative compliance pathways for affected newly constructed, modified, and reconstructed fossil fuel-fired steam generating units. We are finalizing an emission standard for newly constructed highly efficient fossil fuel-fired steam generating units that can be met by capturing and storing approximately 16 to 23 percent of the CO_2 produced from the facility or by utilizing other technologies such as natural gas co-firing. For a subcategory of steam generating units that conduct ''large'' modifications according to definitions in this final rule, we are finalizing an emission standard that is based on a unit-specific emission limitation consistent with each modified unit's best one-year historical performance and can be met through a combination of best operating practices and equipment upgrades. For reconstructed steam generating units, the EPA is finalizing standards of performance based on the performance of the most efficient generation technology available, which we concluded is the use of the best available subcritical steam conditions for small units and the use of supercritical steam conditions for large units. The standards can also be met through other technology options such as natural gas co-firing. In light of these potential alternative compliance pathways, we believe that sources will have ample opportunity to coordinate their response to this rule with any obligations that may be applicable to affected EGUs as a result of the MATS, CSAPR, 316(b), SE ELG and CCR rules, all of which are or soon will be final rules—and to do so in a manner that will help reduce cost and ensure reliability, while also ensuring that all applicable environmental requirements are met.[568]

The EPA is also endeavoring to enable EGUs to comply with applicable obligations under other power sector rules as efficiently as possible (*e.g.,* by facilitating their ability to coordinate planning and investment decisions with respect to those rules) and, where possible, implement integrated compliance strategies. Section IX.C of the preamble to the CAA section 111(d) emission guidelines for existing EGUs that the EPA is finalizing simultaneously with this rule describes such an example with respect to the SE ELG and CCR rules.

In light of the compliance flexibilities we are offering in this action, we believe that sources will have ample opportunity to use cost-effective regulatory strategies and build on their longstanding, successful records of complying with multiple CAA, CWA, and other environmental requirements, while assuring an adequate, affordable, and reliable supply of electricity.

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306 of the Act must require that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

[568] It should be noted that regulatory obligations imposed upon states and sources operate independently under different statutes and sections of statutes; the EPA expects that states and sources will take advantage of available flexibilities as appropriate, but will comply with all relevant legal requirements.

XIII. Impacts of This Action

As explained in the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015) (RIA), available data indicate that, even in the absence of the standards of performance for newly constructed EGUs, existing and anticipated economic conditions will lead electricity generators to choose new generation technologies that will meet the standards without installation of additional controls. Therefore, based on the analysis presented in Chapter 4 of the RIA, the EPA projects that this final rule will result in negligible CO_2 emission changes, quantified benefits, and costs on owners and operators of newly constructed EGUs by 2022.[569] This conclusion is based on the EPA's own modeling as well as projections by EIA. While the primary conclusion of the analysis presented in the RIA is that the standards for newly constructed EGUs will result in negligible costs and benefits, the EPA has also performed several illustrative analyses that show the potential impacts of the rule if certain key assumptions were to change. This includes an analysis of the impacts under a range of natural gas prices and the costs and benefits associated with building an illustrative coal-fired EGU with CCS. These are presented in Chapter 5 of the RIA.

As also explained in the RIA for this final rule, the EPA also expects that few sources will trigger either the NSPS modification or reconstruction provisions that we are finalizing in this rule. In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

A. What are the air impacts?

As explained immediately above, the EPA does not anticipate that this final rule will result in notable CO_2 emission changes by 2022 as a result of the standards of performance for newly constructed EGUs. The owners of newly constructed EGUs will likely choose technologies, primarily NGCC, which meet the standards even in the absence of this rule due to existing economic conditions as normal business practice.

As also explained immediately above, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis.

New steam generating EGUs that choose to comply with the final standard of performance by implementing partial post-combustion CCS are likely to use commercially-available amine-based capture systems. Some concern has been raised regarding emissions of amines and amine degradation by-products (*e.g.,* NH_3) from the capture process. To reduce the amine emissions, MHI introduced the first optimized washing system within an absorber column in 1994, and developed a proprietary washing system in 2003. In that system, a proprietary reagent is added to the water washing section to capture amine impurities such as amine, degraded amine, ammonia, formaldehyde, acetaldehyde, carbonic acids and nitrosamines.[570] MHI has continued to improve this technology for further reduction of amine emissions and established an ''advanced amine emission reduction system''.

Research performed by MHI at Alabama Power's Plant Barry indicated that an increasing SO_3 content in the flue gas caused a significant increase of amine emissions. During testing, at Plant Barry, MHI applied its proprietary washing system and confirmed that the amine emission were drastically reduced.[571] Others have also studied emissions and control strategies and have determined that a conventional multi-stage water wash and mist eliminator at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products emissions.[572] [573] Additional research continues in this area.

B. Endangered Species Act

Consistent with the requirements of section 7(a)(2) of the Endangered Species Act (ESA), the EPA has also considered the effects of this rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed endangered or threatened species or the designated critical habitat of such species and whether consultation with the U.S. Fish and Wildlife Service (FWS) and/or National Marine Fisheries Service (together, the Services) is required by the ESA. Section 7(a)(2) of the ESA requires federal agencies, in consultation with the Service(s), to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. 16 U.S.C. 1536(a)(2). Under relevant implementing regulations, ESA section 7(a)(2) applies only to actions where there is discretionary federal involvement or control. 50 CFR 402.03. Further, under the regulations consultation is required only for actions that ''may affect'' listed species or designated critical habitat. 50 CFR 402.14. Consultation is not required where the action has no effect on such species or habitat. Under this standard, it is the federal agency taking the action that evaluates the action and determines whether consultation is required. *See* 51 FR 19926, 19949 (June 3, 1986). Effects of an action include both the direct and indirect effects that will be added to the environmental baseline. 50 CFR 402.02. Direct effects are the direct or immediate effects of an action on a listed species or its habitat.[574] Indirect effects are those that are ''caused by the proposed action and are later in time, but still are reasonably certain to occur.'' *Id.* To trigger the consultation requirement, there must thus be a causal connection between the federal action, the effect in question, and the listed species, and if the effect is indirect, it must be reasonably certain to occur.

The EPA notes that the projected environmental effects of this final action are positive: Reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (SO_X and NO_X). The EPA recognizes that beneficial effects to listed species can, as a general matter, result in a ''may affect'' determination under the ESA. However, the EPA's assessment that the rule will have an overall net positive environmental effect by virtue of reducing emissions of certain air pollutants does not address whether the rule may affect any listed species or designated critical habitat for ESA section 7(a)(2) purposes and does not constitute any finding of effects for that purpose. The fact that the rule will have overall positive effects on the national

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[569] Conditions in the analysis year of 2022 are represented by a model year of 2020.

[570] Sharma, S.; Azzi, M.; ''A critical review of existing strategies for emission control in the monoethanolamine-based carbon capture process and some recommendations for improved strategies'', *Fuel,* 121, 178 (2014).

[571] Kamijo, T.; et al., ''SO_3 Impact on Amine Emission and Emission Reduction Technology'', *Energy Procedia,* Volume 37, 1793 (2013).

[572] Sharma, S. (2014).

[573] Mertens, J.; et al., ''Understanding ethanolamine (MEA) and ammonia emissions from amine based post combustion carbon capture: Lessons learned from field tests'', *Int'l J. of GHG Control,* 13, 72 (2013).

[574] *See* Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4–25(March 1998) (providing examples of direct effects: *e.g.,* driving an off road vehicle through the nesting habitat of a listed species of bird and destroying a ground nest; building a housing unit and destroying the habitat of a listed species).

and global environment does not mean that the rule may affect any listed species in its habitat or the designated critical habitat of such species within the meaning of ESA section 7(a)(2) or the implementing regulations or require ESA consultation.

The EPA notes that the emission reductions achieved by the rule are projected to be minor. See Section XIII.F and G. below, and RIA chapter 4. Although the final rule imposes substantial controls on CO_2 emissions, we project few if any new fossil fuel-fired steam generating units to be built. Emissions reductions from turbines are likewise projected to be minimal. Moreover, we reasonably project that capacity additions during the analysis period out to 2022 would already be compliant with the rule's requirements (*e.g.,* natural gas combined cycle units, low capacity factor natural gas combustion turbines, and small amounts of coal-fired units with CCS supported by federal and state funding). See RIA chapter 4.

With respect to the projected GHG emission reductions, the EPA does not believe that such minor reductions trigger ESA consultation requirements under section 7(a)(2). In reaching this conclusion, the EPA is mindful of significant legal and technical analysis undertaken by FWS and the U.S. Department of the Interior (DOI) in the context of listing the polar bear as a threatened species under the ESA. In that context, in 2008, FWS and DOI expressed the view that the best scientific data available were insufficient to draw a causal connection between GHG emissions and effects on the species in its habitat.[575] The DOI Solicitor concluded that where the effect at issue is climate change, proposed actions involving GHG emissions cannot pass the ''may affect'' test of the section 7 regulations and thus are not subject to ESA consultation.

The EPA has also previously considered issues relating to GHG emissions in connection with the requirements of ESA section 7(a)(2) and has supplemented DOI's analysis with additional consideration of GHG modeling tools and data regarding listed species. The EPA evaluated this same issue in the context of the light duty vehicle GHG emission standards for model years 2012–2016 and 2017–2025. There the agency projected GHG emission reductions many orders of magnitude greater over the lifetimes of the model years in question[576] and, based on air quality modeling of potential environmental effects, concluded that ''EPA knows of no modeling tool which can link these small, time-attenuated changes in global metrics to particular effects on listed species in particular areas. Extrapolating from global metric to local effect with such small numbers, and accounting for further links in a causative chain, remain beyond current modeling capabilities.'' EPA, *Light Duty Vehicle Greenhouse Gas Standards and Corporate Average Fuel Economy Standards,* Response to Comment Document for Joint Rulemaking at 4–102 (Docket EPA–OAR–HQ–2009–4782). The EPA reached this conclusion after evaluating issues relating to potential improvements relevant to both temperature and oceanographic pH outputs. The EPA's ultimate finding was that ''any potential for a specific impact on listed species in their habitats associated with these very small changes in average global temperature and ocean pH is too remote to trigger the threshold for ESA section 7(a)(2).''*Id.* The EPA believes that the same conclusions apply to the present action, given that the projected CO_2 emission reductions are *far* less than those projected for either of the light duty vehicle rules. *See, e.g., Ground Zero Center for Non-Violent Action* v. *U.S. Dept. of Navy,* 383 F. 3d 1082, 1091–92 (9th Cir. 2004) (where the likelihood of jeopardy to a species from a federal action is extremely remote, ESA does not require consultation). The EPA's conclusion is entirely consistent with DOI's analysis regarding ESA requirements in the context of federal actions involving GHG emissions.[577]

The EPA received a comment on the proposal referencing a prior letter sent to the EPA by three U.S. Senators,[578] which asserted that the rule will cause a shift to alternative sources of energy such as wind and solar and that such facilities may have impacts on listed species. The comment inquired regarding ESA consultation in connection with the rule. We reiterate that no consultation is required for a rule without potential for a specific impact on listed species in their habitats.

C. What are the energy impacts?

This final rule is not anticipated to have a notable effect on the supply, distribution, or use of energy. As previously stated, the EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this rule even in its absence, primarily NGCC units, because of existing and expected market conditions. As also previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis.

D. What are the water and solid waste impacts?

This final rule is not anticipated to have notable impacts on water or solid waste. As we have noted, the EPA believes that utilities and project developers will choose to build new EGUs that comply with the regulatory requirements of this rule even in its absence, primarily through the construction of new NGCC units. As also previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis. Still there are expected to be a small number of coal plants with CCS and the use of CCS systems (especially post-combustion system) will increase the amount of water used at the facility. If those plants utilize partial CCS to meet the final standard of performance (*i.e.,* approximately 16 to 23 percent capture), the increased water use will not be significant. See Section V.O.2. The EPA is unaware of any solid waste impact resulting from this rule.[579]

E. What are the compliance costs?

For steam generating EGUs, the EPA has carefully analyzed the costs of meeting the promulgated standard of performance for a highly efficient SCPC

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[575] *See, e.g.,* 73 FR 28212, 28300 (May 15, 2008); Memorandum from David Longly Bernhardt, Solicitor, U.S. Department of the Interior re: ''Guidance on the Applicability of the Endangered Species Act's Consultation Requirements to Proposed Actions Involving the Emission of Greenhouse Gases'' (Oct. 3, 2008).

[576] *See* 75 FR at 25438 Table I.C 2–4 (May 7, 2010); 77 FR at 62894 Table III–68 (Oct. 15, 2012).

[577] The EPA has received correspondence from Members of Congress asserting that the Services have identified several listed species affected by global climate change. The EPA's assessment of ESA requirements in connection with the present rule does not address whether global climate change may, as a general matter, be a relevant consideration in the status of certain listed species. Rather, the requirements of ESA section 7(a)(2) must be considered and applied to the specific action at issue. As explained above, the EPA's conclusion that ESA section 7(a)(2) consultation is not required here is premised on the specific facts and circumstances of the present rule and is fully consistent with prior relevant analyses conducted by DOI, FWS, and the EPA.

[578] *See* Letter from David Vitter, James M. Inhofe, and Mike Crapo, United States Senate Committee on Environment and Public Works, to Gina McCarthy, Administrator, U.S. Environmental Protection Agency, and Dan Ashe, Director, U.S. Fish and Wildlife Service, dated March 6, 2014.

[579] Estimated costs for the rule include costs for fly ash and bottom ash disposal and for spent solvent recovery and handling. See ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3'', DOE/NETL–2015/1723 (July 2015) at pp. 43, 130.

using partial CCS and found these costs to be reasonable. See Sections V.H and I above. This analysis assumes new capacity not otherwise compliant with the standards would be constructed. Based on the analysis in chapter 4 of the RIA, the EPA believes the standards of performance for newly constructed EGUs will have no notable compliance costs, because electric power companies are expected to build new EGUs that comply with the regulatory requirements of this final rule even in the absence of the rule, primarily NGCC units, due to existing and expected market conditions. While the EPA's analysis and projections from EIA continue to show that the rule is likely to result in negligible costs and benefits due to existing generation choices, the EPA recognizes that some companies may choose to construct coal or other fossil fuel-fired units and has set standards for these units accordingly. For this reason, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired unit with CCS.

In addition, the EPA believes the standards of performance for modified and reconstructed EGUs will have minimal associated compliance costs, because, as previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis.

F. What are the economic and employment impacts?

The EPA does not anticipate that this final rule will result in notable CO_2 emission changes, energy impacts, monetized benefits, costs, or economic impacts by 2022 as a result of the standards of performance for newly constructed EGUs. The owners of newly constructed EGUs will likely choose technologies that meet the standards even in the absence of this rule, due to existing economic conditions as normal business practice. Likewise, the EPA believes this rule will not have any impacts on the price of electricity, employment or labor markets, or the U.S. economy. See RIA chapter 4.6.[580]

As previously stated, the EPA anticipates few units will trigger the NSPS modification or reconstruction provisions. As with the new source standards, the EPA does not expect macroeconomic or employment impacts as a result of the standards.

G. What are the benefits of the final standards?

We are not projecting direct monetized climate benefits in terms of CO_2 emission reductions associated with these standards of performance. This is because, as stated above, the EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this rule even in its absence, primarily NGCC units, because of existing and expected market conditions. See RIA chapter 4. Moreover, a cost-reasonable standard is, in fact, what will drive new technology deployment and provide a path forward for new coal-fired capacity. See Section V.L above.

As also previously stated, the EPA anticipates few units will trigger the NSPS modification or reconstruction provisions. In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

XIV. Statutory and Executive Order Reviews

Additional information about these Statutory and Executive Orders can be found at *http://www2.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 final action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. It is a significant regulatory action because it raises novel legal or policy issues arising out of legal mandates. Any changes made in response to OMB recommendations have been documented in the established dockets for this action under Docket ID No. EPA–HQ–OAR–2013–0495 (Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units) and Docket ID No. EPA–HQ–OAR–2013–0603 (Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units). The EPA prepared an economic analysis of the potential costs and benefits associated with this action. This analysis, which is contained in the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015), is available in both dockets.

The EPA does not anticipate that this final action will result in any notable compliance costs. Specifically, we believe that the standards for newly constructed fossil fuel-fired EGUs (electric utility steam generating units and natural gas-fired stationary combustion turbines) will have negligible costs associated with it over a range of likely sensitivity conditions because electric power companies will choose to build new EGUs that comply with the regulatory requirements of this action even in the absence of the action, because of existing and expected market conditions. (See the RIA for further discussion of sensitivities). The EPA does not project any new coal-fired steam generating units without CCS to be built in the absence of this action. However, because some companies may choose to construct coal or other fossil fuel-fired EGUs, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired EGU with CCS.

The EPA also believes that the standards for modified and reconstructed fossil fuel-fired EGUs will result in minimal compliance costs, because, as previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis (through 2022). In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

B. Paperwork Reduction Act (PRA)

The information collection activities in this final action 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 2465.03. Separate ICR documents were prepared and submitted to OMB for the proposed standards for newly constructed EGUs (EPA ICR number 2465.02) and the proposed standards for modified and reconstructed EGUs (EPA ICR number 2506.01). Because the CO_2 standards for newly constructed, modified, and reconstructed EGUs will be included in the same new subpart (40 CFR part 60, subpart TTTT) and are being finalized in the same action, the ICR document for this action includes estimates of the information collection burden on owners and operators of newly constructed, modified, and reconstructed EGUs. Estimated cost burden is based on 2013 Bureau of Labor Statistics (BLS) labor cost data.

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[580] The employment analysis in the RIA is part of the EPA's ongoing effort to ''conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]'' pursuant to CAA section 321(a).

Thus, all burden estimates are in 2013 dollars. Burden is defined at 5 CFR 1320.3(b). You can find a copy of the ICR in the dockets for this action (Docket ID Numbers EPA–HQ–OAR–2013–0495 and EPA–HQ–OAR–2013–0603), and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

The recordkeeping and reporting requirements in this final action are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

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 action.

1. Newly Constructed EGUs

This final action will impose minimal new information collection burden on owners and operators of affected newly constructed fossil fuel-fired EGUs (steam generating units and stationary combustion turbines) beyond what those sources would already be subject to under the authorities of CAA parts 75 and 98. OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control numbers 2060–0626 and 2060–0629, respectively. Apart from certain reporting costs to comply with the emission standards under the rule, there are no new information collection costs, as the information required by the standards for newly constructed EGUs is already collected and reported by other regulatory programs.

The EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of the rule because of existing and expected market conditions. The EPA does not project any newly constructed coal-fired steam generating units that commenced construction after proposal (January 8, 2014) to commence operation over the 3-year period covered by this ICR. We estimate that 12 affected newly constructed NGCC units and 25 affected newly constructed natural gas-fired simple cycle combustion turbines will commence operation during that time period. As a result of this final action, owners or operators of those newly constructed units will be required to prepare a summary report, which includes reporting of emissions and downtime, every 3 months.

2. Modified and Reconstructed EGUs

This final action is not expected to impose an information collection burden under the provisions of the PRA on owners and operators of affected modified and reconstructed fossil fuel-fired EGUs (steam generating units and stationary combustion turbines). As previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis. Specifically, the EPA believes it unlikely that fossil fuel-fired electric utility steam generating units or stationary combustion turbines will take actions that would constitute modifications or reconstructions as defined under the EPA's NSPS regulations. Accordingly, the standards for modified and reconstructed EGUs are not anticipated to impose any information collection burden over the 3-year period covered by this ICR. We have estimated, however, the information collection burden that would be imposed on an affected EGU if it was modified or reconstructed.

Although not anticipated, if an EGU were to modify or reconstruct, this final action would impose minimal information collection burden on those affected EGUs beyond what they would already be subject to under the authorities of CAA 40 CFR parts 75 and 98. As described above, the OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations. Apart from certain reporting costs to comply with the emission standards under the rule, there would be no new information collection costs, as the information required by the final rule is already collected and reported by other regulatory programs.

As stated above, although the EPA expects few sources will trigger either the NSPS modification or reconstruction provisions, if an EGU were to modify or reconstruct during the 3-year period covered by this ICR, the owner or operator of the EGU will be required to prepare a summary report, which includes reporting of emissions and downtime, every 3 months. The annual reporting burden for such a unit is estimated to be $1,333 and 16 labor hours. There are no annualized capital costs or O&M costs associated with burden for modified or reconstructed EGUs.

3. Information Collection Burden

The annual information collection burden for newly constructed, modified, and reconstructed EGUs consists only of reporting burden as explained above. The annual reporting burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $60,977 and 651 labor hours. There are no annualized capital costs or O&M costs associated with burden for newly constructed, modified, or reconstructed EGUs. Average burden hours per response are estimated to be 7 hours. The total number of respondents over the 3-year ICR period is estimated to be 62.

C. Regulatory Flexibility Act (RFA)

I certify that this final action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule.

1. Newly Constructed EGUs

The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. RIA Chapter 4. The EPA does not project any new coal-fired steam generating units without CCS to be built. We expect that any newly constructed natural gas-fired stationary combustion turbines will meet the standards. We do not include an analysis of the illustrative impacts on small entities that may result from implementation of the final rule because we anticipate negligible compliance costs over a range of likely sensitivity conditions as a result of the standards for newly constructed EGUs. Thus the cost-to-sales ratios for any affected small entity would be zero costs as compared to annual sales revenue for the entity. Accordingly, there are no anticipated economic impacts as a result of the standards for newly constructed EGUs. (See the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015) for further discussion of sensitivities.) We have therefore concluded that this final action will have no net regulatory burden for all directly regulated small entities.

2. Modified and Reconstructed EGUs

The EPA expects few fossil fuel-fired electric utility steam generating units to trigger the NSPS modification provisions in the period of analysis. An NSPS modification is defined as a physical or operational change that increases the source's maximum achievable hourly rate of emissions. The EPA does not believe that there are likely to be EGUs that will take actions that would constitute modifications as defined under the EPA's NSPS regulations.

In addition, the EPA expects few reconstructed fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines in the period of analysis. Reconstruction occurs when a single project replaces components or equipment in an existing facility and exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources. However, we do not anticipate that the rule would impose significant costs on those sources, including any that are owned by small entities. (See the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015).

D. Unfunded Mandates Reform Act (UMRA)

This final 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.

The EPA believes the final rule will have negligible compliance costs on owners and operators of newly constructed EGUs over a range of likely sensitivity conditions because electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the rule because of existing and expected market conditions. The EPA does not project any new coal-fired steam generating units without CCS to be built and expects that any newly constructed natural gas-fired stationary combustion turbines will meet the standards. (See the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015) for further discussion of sensitivities.)

As previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources. However, we do not anticipate that the rule would impose significant costs on those sources. (See the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015).)

We have therefore concluded that the standards for newly constructed, modified, and reconstructed EGUs do not impose enforceable duties on any state, local or tribal governments, or the private sector, that may result in expenditures by state, local and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. We have also concluded that this action does not have regulatory requirements that might significantly or uniquely affect small governments. The threshold amount established for determining whether regulatory requirements could significantly affect small governments is $100 million annually and, as stated above, we have concluded that the final action will not result in expenditures of $100 million or more in any one year. Specifically, the EPA does not project any new coal-fired steam generating units without CCS to be built and expects that any newly constructed natural gas-fired stationary combustion turbines will meet the standards. Further, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis.

E. Executive Order 13132: Federalism

This final 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. The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. In addition, as previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. We, therefore, anticipate that the final rule will impose minimal compliance costs.

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

This final action does not have tribal implications as specified in Executive Order 13175. The final rule will impose requirements on owners and operators of newly constructed, modified, and reconstructed EGUs. The EPA is aware of three facilities with coal-fired steam generating units, as well as one facility with natural gas-fired stationary combustion turbines, located in Indian Country, but is not aware of any EGUs owned or operated by tribal entities. We note that because the rule addresses CO_2 emissions from newly constructed, modified, and reconstructed EGUs, it will affect existing EGUs such as those located at the four facilities in Indian Country only if those EGUs were to take actions constituting modifications or reconstructions as defined under the EPA's NSPS regulations. As previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis. Thus, the rule will neither impose substantial direct compliance costs on tribal governments nor preempt Tribal law. Accordingly, Executive Order 13175 does not apply to this action.

Nevertheless, because the EPA is aware of Tribal interest in carbon pollution standards for the power sector and, consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA offered consultation with tribal officials during development of this rule. Prior to the April 13, 2012 proposal (77 FR 22392), the EPA sent consultation letters to the leaders of all federally recognized tribes. Although only newly constructed, modified, and reconstructed EGUs will be affected by this action, the EPA's consultation regarded planned actions for new and existing sources. The letters provided information regarding the EPA's development of NSPS and emission guidelines for EGUs and offered consultation. A consultation/outreach meeting was held on May 23, 2011, with the Forest County Potawatomi Community, the Fond du Lac Band of Lake Superior Chippewa Reservation, and the Leech Lake Band of Ojibwe. A description of that consultation is included in the preamble to the proposed standards for new EGUs (79 FR 1501, January 8, 2014).

The EPA also offered consultation to the leaders of all federally recognized tribes after the proposed action for newly constructed EGUs was signed on September, 20, 2013. On November 1, 2013, the EPA sent letters to tribal leaders that provided information regarding the EPA's development of carbon pollution standards for new, modified, reconstructed and existing EGUs and offered consultation. No tribes requested consultation regarding the standards for newly constructed EGUs.

In addition to offering consultation, the EPA also conducted outreach to tribes during development of this rule. The EPA held a series of listening sessions prior to proposal of GHG standards for newly constructed EGUs. Tribes participated in a session on February 17, 2011, with the state agencies, as well as in a separate session with tribes on April 20, 2011. The EPA also held a series of listening sessions prior to proposal of GHG standards for modified and reconstructed EGUs and GHG emission guidelines for existing EGUs. Tribes participated in a session on September 9, 2013, together with the state agencies, as well as in a separate tribe-only session on September 26, 2013. In addition, an outreach meeting was held on September 9, 2013, with tribal representatives from some of the federally recognized tribes. The EPA also met with tribal environmental staff with the National Tribal Air Association, by teleconference, on July 25, 2013, and December 19, 2013. Additional detail regarding this stakeholder outreach is included in the preamble to the proposed emission guidelines for existing EGUs (79 FR 34830, June 18, 2014).

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

This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866. While the action is not subject to Executive Order 13045, the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the agency has evaluated the environmental health and welfare effects of climate change on children.

CO_2 is a potent GHG that contributes to climate change and is emitted in significant quantities by fossil fuel-fired power plants. As stated above, the EPA believes the final rule will have negligible effects on owners and operators of newly constructed EGUs over a range of likely sensitivity conditions because electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the rule because of existing and expected market conditions. However, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired unit with CCS. RIA chapter 5. Under these scenarios, the rule would result in substantial reductions of both CO_2, and also fine particulate matter (sulfate PM 2.5) such that net quantifiable benefits exceed regulatory costs under a range of assumptions. Under these same scenarios, this rule would have a positive effect for children's health.

The assessment literature cited in the EPA's 2009 Endangerment Finding concluded that certain populations and lifestages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects. The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience.

These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

More detailed information on the impacts of climate change to human health and welfare is provided in Section II.A of this preamble.

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

This final 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. See Section V.O.3 above. The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. In addition, as previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. Thus, this action is not anticipated to have notable impacts on emissions, costs or energy supply decisions for the affected electric utility industry.

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

This final action involves technical standards. The EPA has decided to use 10 voluntary consensus standards (VCS) in the final rule.

One VCS, American National Standards Institute (ANSI) Standard C12.20, ''American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes,'' is cited in the final rule to assure consistent monitoring of electric output. This standard establishes the physical aspects and acceptable performance criteria for 0.2 and 0.5 accuracy class electricity meters. This standard is available at *http://www.ansi.org* or by mail at American National Standards Institute (ANSI), 25 W. 43rd Street, 4th Floor, New York, NY 10036.

Six VCS, ASTM Methods D388–99, ''Standard Classification of Coals by Rank''; D396–98, ''Standard Specification for Fuel Oils''; D975–08a, ''Standard Specification for Diesel Fuel Oils''; D3699–08, ''Standard Specification for Kerosine''; D6751–11b, ''Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels''; and D7467–10, ''Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20)'' are cited in the final rule to identify the different fuel types. ASTM D388 covers the classification of coals by rank, that is, according to their degree of metamorphism, or progressive alteration, in the natural series from lignite to anthracite. ASTM D396 covers grades of fuel oil intended for use in various types of fuel-oil-burning equipment under various climatic and operating conditions. These include Grades 1 and 2 (for use in domestic and small industrial burners), Grade 4 (heavy distillate fuels or distillate/residual fuel blends used in commercial/industrial burners equipped for this viscosity range), and Grades 5 and 6 (residual fuels of increasing viscosity and boiling range, used in industrial burners). ASTM D975 covers seven grades of diesel fuel oils based on grade, sulfur content, and volatility. These grades range from *Grade No. 1–D S15* (a special-purpose, light middle distillate fuel for use in diesel engine applications requiring a fuel with 15 ppm sulfur (maximum) and higher volatility than that provided by Grade No. 2–D S15 fuel) to *Grade No. 4–D* (a heavy distillate fuel, or a blend of distillate and residual oil, for use in low- and medium-speed diesel engines in applications involving predominantly constant speed and load). ASTM D3699 covers two grades of kerosene suitable for use in critical kerosene burner applications: No. 1–K (a special low-sulfur grade kerosene suitable for use in non-flue-connected kerosene burner appliances and for use in wick-fed illuminating lamps) and No. 2–K (a regular grade kerosene suitable for use in flue-connected burner appliances and for use in wick-fed illuminating lamps). ASTM D6751 covers biodiesel (B100) Grades S15 and S500 for use as a blend component with middle distillate fuels. ASTM D7467 covers fuel blend grades of 6 to 20 volume percent biodiesel with the remainder being a light middle or middle distillate diesel fuel, collectively designated as B6 to B20. These standards are available at *http://www.astm.org* or by mail at ASTM International, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, PA 19428–2959.

Two VCS, American Society of Mechanical Engineers (ASME) Performance Test Codes PTC 22–2014, ''Performance Test Codes on Gas Turbines'' and PTC 46–1996, ''Performance Test Codes on Overall Plant Performance'' are cited in the final rule for their guidance on measuring the performance of stationary combustion turbines. PTC–22 provides directions and rules for conduct and report of results of thermal performance tests for open cycle simple cycle combustion turbines. The object is to determine the thermal performance of the combustion turbine when operating at test conditions, and correcting these test results to specified reference conditions. PTC 22 provides explicit procedures for the determination of the following performance results: corrected power, corrected heat rate (efficiency), corrected exhaust flow, corrected exhaust energy, and corrected exhaust temperature. Tests may be designed to satisfy different goals, including absolute performance and comparative performance. The objective of PTC 46 is to provide uniform test methods and procedures for the determination of the thermal performance and electrical output of heat-cycle electric power plants and combined heat and power units (PTC 46 is not applicable to simple cycle combustion turbines). Test results provide a measure of the performance of a power plant or thermal island at a specified cycle configuration, operating disposition and/or fixed power level, and at a unique set of base reference conditions. PTC 46 provides explicit procedures for the determination of the following performance results: corrected net power, corrected heat rate, and corrected heat input. These standards are available at *http://www.asme.org* or by mail at American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016–5990.

One VCS, International Organization for Standardization method ISO 2314:2009, ''Gas Turbines—Acceptance Tests'' is cited in the final rule for its guidance on determining performance characteristics of stationary combustion turbines. ISO 2314 specifies guidelines and procedures for preparing, conducting and reporting thermal-acceptance tests in order to determine and/or verify electrical power output, mechanical power, thermal efficiency (heat rate), turbine exhaust gas energy and/or other performance characteristics of open-cycle simple cycle combustion turbines using combustion systems supplied with gaseous and/or liquid fuels as well as closed-cycle and semi-closed-cycle simple cycle combustion turbines. It can also be applied to simple cycle combustion turbines in combined cycle power plants or in connection with other heat recovery systems. ISO 2314 includes procedures for the determination of the following performance parameters, corrected to the reference operating parameters: electrical or mechanical power output (gas power, if only gas is supplied), thermal efficiency or heat rate; and combustion turbine engine exhaust energy (optionally exhaust temperature and flow). This standard is available at *http://www.iso.org/iso/home.htm* or by mail at International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland.

Since no EPA Methods were used, there was no need for a NTTAA search. The rule also requires use of appendices A, B, D, F and G to 40 CFR part 75 and the procedures under 40 CFR 98.33; these appendices contain standards that have already been reviewed under the NTTAA.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

Leading up to this rulemaking the EPA summarized the public health and welfare effects of GHG emissions in its 2009 Endangerment Finding. As part of the Endangerment Finding, the Administrator considered climate change risks to minority or low-income populations, finding that certain parts of the population may be especially vulnerable based on their circumstances. Populations that were found to be particularly vulnerable to climate change risks include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. See Sections XIV.F and G, above, where the EPA discusses Consultation and Coordination with Tribal Governments and Protection of Children. The Administrator placed weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

The record for the 2009 Endangerment Finding summarizes the strong scientific evidence in the major assessment reports by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies that the potential impacts of climate change raise environmental justice issues. These reports concluded that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The 2009 Endangerment Finding record also specifically noted that Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities are already experiencing disruptive impacts, including coastal erosion and shifts in the range or abundance of wild species crucial to their livelihoods and well-being.

The most recent assessments continue to strengthen scientific understanding of climate change risks to minority and low-income populations in the United States.[581] The new assessment literature provides more detailed findings regarding these populations' vulnerabilities and projected impacts they may experience. In addition, the most recent assessment reports provides new information on how some communities of color may be uniquely vulnerable to climate change health impacts in the United States. These reports find that certain climate change related impacts—including heat waves, degraded air quality, and extreme weather events—have disproportionate effects on low-income and some communities of color, raising environmental justice concerns. Existing health disparities and other inequities in these communities increase their vulnerability to the health effects of climate change. In addition, assessment reports also find that climate change poses particular threats to health, wellbeing, and ways of life of indigenous peoples in the United States.

As the scientific literature presented above and in the Endangerment Finding illustrates, low income communities and some communities of color are especially vulnerable to the health and other adverse impacts of climate change.

The EPA believes the human health or environmental risk addressed by this final action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. The final rule limits GHG emissions from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units and newly constructed and modified stationary combustion turbines by establishing national emission standards for CO_2.

The EPA has determined that the final rule will not result in disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations because the rule is not anticipated to notably affect the level of protection provided to human health or the environment. The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. The EPA does not project any new coal-fired steam generating units without CCS to be built and expects that any newly built natural gas-fired stationary combustion turbines will meet the standards. In addition, as previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. This final rule will ensure that, to whatever extent there are newly constructed, modified, and reconstructed EGUs, they will use the best performing technologies to limit emissions of CO_2.

K. Congressional Review Act (CRA)

This final action is subject to the 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).

XV. Withdrawal of Proposed Standards for Certain Modified Sources

In this action, as discussed above in Sections IV and VI, the EPA is issuing final standards of performance for affected fossil fuel-fired steam generating EGUs that implement modifications resulting in an increase of CO_2 emissions (in lb/hr) of more than 10 percent. In addition, the EPA is withdrawing the proposed standards of performance for emissions of carbon dioxide (CO_2) from modified fossil fuel-fired EGUs not covered by those final standards. Specifically, the EPA is withdrawing the proposed standards for fossil fuel-fired steam generating EGUs that implement modifications resulting in an increase of CO_2 emissions (in lb/hr) of less than or equal to 10 percent. A detailed rationale for the withdrawal of these proposed standards is provided in Section VI above.

The EPA is also, in this action, withdrawing proposed standards for modified stationary combustion turbines. A detailed rationale for the withdrawal of these proposed standards is provided in Section IX above.

The proposed standards for modified fossil fuel-fired EGUs that the EPA is withdrawing in this action were published in the **Federal Register** on June 18, 2014 (79 FR 34960).

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[581] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, 841 pp.

IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 1132 pp.

IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 688 pp.

XVI. Statutory Authority

The statutory authority for this action is provided by sections 111, 301, 302, and 307(d)(1)(C) of the CAA as amended (42 U.S.C. 7411, 7601, 7602, 7607(d)(1)(C)). This action is also subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects

40 CFR Part 60

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

40 CFR Part 70

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 71

Environmental protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements.

40 CFR Part 98

Environmental protection, Greenhouse gases and monitoring, Reporting and recordkeeping requirements.

Dated: August 3, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, parts 60, 70, 71, and 98 of the Code of the Federal Regulations are amended 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.*

■ 2. Section 60.17 is amended by:
■ a. Redesignating paragraphs (d) through (t) as paragraphs (e) through (u) and adding paragraph (d);
■ b. In newly redesignated paragraph (g), further redesignating paragraph (g)(15) as paragraph (g)(17) and adding paragraphs (g)(15) and (16);
■ c. In newly redesignated paragraph (h), revising paragraphs (h)(37), (42), (46), (138), (187), and (190); and
■ c. In newly redesignated paragraph (m), further redesignating paragraph (m)(1) as paragraph (m)(2) and adding paragraph (m)(1).

The revisions and additions read as follows:

§ 60.17 Incorporations by reference.

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(d) The following material is available for purchase from the American National Standards Institute (ANSI), 25 W. 43rd Street, 4th Floor, New York, NY 10036, Telephone (212) 642–4980, and is also available at the following Web site: *http://www.ansi.org.*

(1) ANSI No. C12.20–2010 American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010), IBR approved for § 60.5535(d).

(2) [Reserved]

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(g) * * *

(15) ASME PTC 22–2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014), IBR approved for § 60.5580.

(16) ASME PTC 46–1996, Performance Test Code on Overall Plant Performance, (Issued October 15, 1997), IBR approved for § 60.5580.

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(h) * * *

(37) ASTM D388–99 (Reapproved 2004) $^{\varepsilon1}$ Standard Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, 60.251, and 60.5580.

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(42) ASTM D396–98, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), 60.111a(b), and 60.5580.

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(46) ASTM D975–08a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.41b 60.41c, and 60.5580.

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(138) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

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(187) 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, and 60.5580.

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(190) 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, and 60.5580.

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(1) ISO 2314:2009(E), Gas turbines–Acceptance tests, Third edition (December 15, 2009), IBR approved for § 60.5580.

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■ 3. Part 60 is amended by adding subpart TTTT to read as follows:

Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

Applicability

§ 60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit, IGCC, or a stationary combustion turbine that commences construction after January 8, 2014 or commences modification or reconstruction after June 18, 2014. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU.

§ 60.5509 Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit, IGCC, or stationary combustion turbine that commenced construction after January 8, 2014 or commenced reconstruction after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any steam generating unit or IGCC that commenced modification after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (10) of this section.

(1) Your EGU is a steam generating unit or IGCC that is currently and always has been subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of combusting 50 percent or more non-fossil fuel and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline).

(9) The proposed Washington County EGU project described in Air Quality Permit No. 4911–303–0051–P–01–0 issued by the Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, effective April 8, 2010, provided that construction had not commenced for NSPS purposes as of January 8, 2014.

(10) The proposed Holcomb EGU project described in Air Emission Source Construction Permit 0550023 issued by the Kansas Department of Health and Environment, Division of Environment, effective December 16, 2010, provided that construction had not commenced for NSPS purposes as of January 8, 2014.

Emission Standards

§ 60.5515 Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the ‘‘pollutant that is subject to the standard promulgated under section 111 of the Act’’ shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the ‘‘pollutant that is subject to the standard promulgated under section 111 of the Act’’ shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the ‘‘pollutant that is subject to any standard promulgated under section 111 of the Act’’ shall be considered to be the pollutant that otherwise is ‘‘subject to regulation’’ as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the ‘‘pollutant that is subject to any standard promulgated under section 111 of the Act’’ shall be considered to be the pollutant that otherwise is ‘‘subject to regulation’’ as defined in 40 CFR 71.2.

§ 60.5520 What CO_2 emission standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in Table 1 or 2 of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term ‘‘gross or net energy output’’ is used, the term that applies to you is ‘‘gross energy output.’’

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term ‘‘gross or net energy output’’ is used, the term that applies to you is ‘‘net energy output.’’ Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Stationary combustion turbines subject to a heat input-based standard in Table 2 of this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). All other stationary combustion turbines subject to a heat input based standard in Table 2 are subject to the requirements in paragraph (d)(2) of this section.

(1) Stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 160 lb CO_2/MMBtu or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 160 lb CO_2/MMBtu or less (*e.g.,* non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

General Compliance Requirements

§ 60.5525 What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See Table 1 or 2 of this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in million Btus (MMBtu) from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using one of the methods under § 60.5535(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

$$CO_2 \text{ emission standard} = \frac{(120 \text{ x } HTIP_{ng})+(160 \text{ x } HTIP_o)}{HTIP_{ng}+HTIP_o} \quad \text{(Eq. 1)}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of lb/MMBtu.
$HTIP_{ng}$ = the heat input in MMBtu from natural gas.
$HTIP_o$ = the heat input in MMBtu from all fuels other than natural gas.
120 = allowable emission rate in lb of CO_2/MMBtu for heat input derived from natural gas.
160 = allowable emission rate in lb of CO_2/MMBtu for heat input derived from all fuels other than natural gas.

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in Table 1 or 2 of this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in § 72.2 of this chapter) on or after October 23, 2015, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under:

(i) Section 63.5555(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 63.5555(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) For an affected EGU that has commenced COMMERCIAL operation (as defined in § 72.2 of this chapter) prior to October 23, 2015:

(i) If the date on which emissions reporting is required to begin under § 75.64(a) of this chapter has passed prior to October 23, 2015, emissions reporting shall begin according to § 63.5555(c)(3)(i) (for Acid Rain program units), or according to § 63.5555(c)(3)(ii)(B) (for units that are not subject to the Acid Rain Program). The first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which the rule becomes effective; or

(ii) If the date on which emissions reporting is required to begin under § 75.64(a) of this chapter occurs on or after October 23, 2015, then the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 63.5555(c)(3)(ii)(A).

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 63.5555(c)(3)(iii).

Monitoring and Compliance Determination Procedures

§ 60.5535 How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter. The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555(c)).

(b) You must determine the hourly CO_2 mass emissions in kilograms (kg) from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected coal-fired EGU or for an IGCC unit you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, you may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and appendices A and B to part 75 of this chapter.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with part 75 of this chapter. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for ''valid operating hours'', as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F–11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 909.1 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G–4 in appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(3) For each ''valid operating hour'' (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 909.1 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation G–4 in appendix G to part 75 of this chapter.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under § 98.33(a)(3) of this chapter.

(d) Consistent with § 60.5520, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb of CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.,* lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to part 75 of this chapter;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under § 98.33(a)(3) of this chapter, you may convert your CO_2 emissions to heat input using the appropriate emission factor in Table C–1 of part 98 of this chapter. If your fuel is not listed in Table C–1, you must determine a fuel-specific carbon-based F-factor (F_c) in accordance with section 12.3.2 of EPA Method 19 of appendix A–7 to this part, and you must convert your CO_2 emissions to heat input using Equation G–4 in appendix G to part 75 of this chapter.

(e) Consistent with § 60.5520, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(f) In accordance with §§ 60.13(g) and 60.5520, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack and are subject to the same emissions standard in Table 1 or 2 of this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as ''stack operating hours'' (as defined in § 72.2 of this chapter). If you attain compliance with the applicable emissions standard in § 60.5520 at the common stack, each affected EGU sharing the stack is in compliance.

(g) In accordance with §§ 60.13(g) and 60.5520 if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in § 72.2 of this chapter) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in Table 1 or 2 of this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in Table 1 or 2 of this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (7) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*i.e.,* either kg/MWh or lb/MMBtu). You must use the hourly CO_2 mass emissions calculated under § 60.5535(b) or (c), as applicable, and either the generating load data from § 60.5535(d)(1) for output-based calculations or the heat input data from § 60.5535(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.,* operating hours for which:

(i) ''Valid data'' (as defined in § 60.5580) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input; or

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535 for all of the valid operating hours in the compliance period.

(5) *Sources subject to output based standards.* For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the

procedures in paragraphs (a)(3)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly gross or net energy output (consistent with § 60.5520) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_{A}}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad \text{(Eq. 3)}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) *Calculation of annual basis for standard.* Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520 if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(b) In accordance with § 60.5520, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (7) of this section and must be less than or equal to the applicable CO_2 emissions standard in Table 1 or 2 of this part, or the emissions standard calculated in accordance with § 60.5525(a)(2).

Notification, Reports, and Records

§ 60.5550 What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see Table 3 of this subpart).

(b) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable, to your affected EGUs.

§ 60.5555 What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525 to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1)(i) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520, the CO_2 emissions standard (as identified in Table 1 or 2 of this part) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with § 75.64(a) of this chapter, *i.e.,* beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in § 75.20(a)(3) of this chapter; or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in § 72.2 of this chapter).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after:

(A) The date on which reporting is required to begin under § 75.64(a) of this chapter, if that date occurs on or after October 23, 2015; or

(B) October 23, 2015, if the date on which reporting would ordinarily be required to begin under § 75.64(a) of this chapter has passed prior to October 23, 2015.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with § 75.4(j) of this chapter, § 75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not ''valid operating hours'' (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under § 72.20 of this chapter; or

(2) The person appointed as the Alternate Designated Representative (ADR) under § 72.22 of this chapter; or

(3) A person (or persons) authorized by the DR or ADR under § 72.26 of this chapter to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission limit, you must report in accordance with the requirements of 40 CFR part 98, subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs on-site, or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs off-site.

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system itself, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560 What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under § 75.53(g) and (h) of this chapter;

(ii) Operating parameter records under § 75.57(b)(1) through (4) of this chapter;

(iii) The records under § 75.57(c)(2) of this chapter, for stack gas volumetric flow rate;

(iv) The records under § 75.57(c)(3) of this chapter for continuous moisture monitoring systems;

(v) The records under § 75.57(e)(1) of this chapter, except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O_2 monitors used to calculate CO_2 concentration;

(vi) The records under § 75.58(c)(1) of this chapter, specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under § 75.58(c)(4) of this chapter, specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under § 75.59(a) of this chapter, specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under § 75.59(a) of this chapter, specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under § 75.59(e) of this chapter.

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in Table 1 or 2 of this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

§ 60.5565 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 3 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570 What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in Table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575 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 (5) 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 emission 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).

§ 60.5580 What definitions apply to this subpart?

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

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388–99 (Reapproved 2004) ε^1 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as ‘‘cogeneration’’) means an electric generating unit that that use a steam generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see § 60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see § 60.17) or ISO 2314 Gas turbines—acceptance tests (incorporated by reference, see § 60.17).

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

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria)

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which 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.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

ISO conditions means 288 Kelvin (15°C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, 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 sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on an annual basis, the gross electric sales to the utility power

distribution system minus purchased power of the thermal host facility or facilities.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales that that result from a system emergency are not included when calculating net-electric sales.

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 EGU plus 100 percent of the useful thermal output; or

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

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means 33 percent or the base load rating design efficiency at the maximum electric production rate (*e.g.,* CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.,* a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

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 turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and 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, 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. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load.

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, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*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 EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter 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 of this chapter 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 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter 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).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in Table 1 or 2 of this subpart.

TABLE 1 OF SUBPART TTTT OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STEAM GENERATING UNITS AND INTEGRATED GASIFICATION COMBINED CYCLE FACILITIES THAT COMMENCED CONSTRUCTION AFTER JANUARY 8, 2014 AND RECONSTRUCTION OR MODIFICATION AFTER JUNE 18, 2014

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed steam generating unit or integrated gasification combined cycle (IGCC).	640 kg CO_2/MWh of gross energy output (1,400 lb CO_2/MWh).
Reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.	910 kg of CO_2 per MWh of gross energy output (2,000 lb CO_2/MWh).
Reconstructed steam generating unit or IGCC that has a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h).	820 kg of CO_2 per MWh of gross energy output (1,800 lb CO_2/MWh).
Modified steam generating unit or IGCC	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than: 1. 1,800 lb CO_2/MWh-gross for units with a base load rating greater than 2,000 MMBtu/h; or 2. 2,000 lb CO_2/MWh-gross for units with a base load rating of 2,000 MMBtu/h or less.

TABLE 2 OF SUBPART TTTT OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STATIONARY COMBUSTION TURBINES THAT COMMENCED CONSTRUCTION AFTER JANUARY 8, 2014 AND RECONSTRUCTION AFTER JUNE 18, 2014 (NET ENERGY OUTPUT-BASED STANDARDS APPLICABLE AS APPROVED BY THE ADMINISTRATOR)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.	450 kg of CO_2 per MWh of gross energy output (1,000 lb CO_2/MWh); or 470 kilograms (kg) of CO_2 per megawatt-hour (MWh) of net energy output (1,030 lb/MWh).
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.	50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO_2/MMBtu).
Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis.	50 kg CO_2/GJ of heat input (120 lb/MMBtu) to 69 kg CO_2/GJ of heat input (160 lb/MMBtu) as determined by the procedures in § 60.5525.

TABLE 3 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A OF PART 60 (GENERAL PROVISIONS) TO SUBPART TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8	Performance tests	No.	
§ 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	Monitoring requirements	No	All monitoring is done according to part 75.

TABLE 3 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A OF PART 60 (GENERAL PROVISIONS) TO SUBPART TTTT—Continued

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.14	Modification	Yes (steam generating units and IGCC facilities). No (stationary combustion turbines.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

PART 70—STATE OPERATING PERMIT PROGRAMS

■ 4. The authority citation for part 70 continues to read as follows:

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

■ 5. In § 70.2, the definition of ''Regulated pollutant (for presumptive fee calculation)'' is amended by:
■ a. Revising the introductory text;
■ b. Removing ''or'' from the end of paragraph (2);
■ c. Removing the period at the end of paragraph (3) and adding ''; or'' in its place; and
■ d. Adding paragraph (4).

The revision and additions read as follows:

§ 70.2 Definitions.

* * * * *

Regulated pollutant (for presumptive fee calculation), which is used only for purposes of § 70.9(b)(2), means any regulated air pollutant except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

■ 6. Section 70.9 is amended by revising paragraph (b)(2)(i), and adding paragraph (b)(2)(v) to read as follows:

§ 70.9 Fee determination and certification.

* * * * *

(b) * * *

(2)(i) The Administrator will presume that the fee schedule meets the requirements of paragraph (b)(1) of this section if it would result in the collection and retention of an amount not less than $25 per year [as adjusted pursuant to the criteria set forth in paragraph (b)(2)(iv) of this section] times the total tons of the actual emissions of each regulated pollutant (for presumptive fee calculation) emitted from part 70 sources and any GHG cost adjustment required under paragraph (b)(2)(v) of this section.

* * * * *

(v) *GHG cost adjustment.* The amount calculated in paragraph (b)(2)(i) of this section shall be increased by the GHG cost adjustment determined as follows: For each activity identified in the following table, multiply the number of activities performed by the permitting authority by the burden hours per activity, and then calculate a total number of burden hours for all activities. Next, multiply the burden hours by the average cost of staff time, including wages, employee benefits and overhead.

Activity	Burden hours per activity
GHG completeness determination (for initial permit or updated application)	43
GHG evaluation for a permit modification or related permit action	7
GHG evaluation at permit renewal	10

* * * * *

PART 71—FEDERAL OPERATING PERMIT PROGRAMS

■ 7. The authority citation for part 71 continues to read as follows:

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

■ 8. In § 71.2, the definition of ''Regulated pollutant (for fee calculation)'' is amended by:
■ a. Removing ''or'' from the end of paragraph (2);
■ b. Removing the period at the end of paragraph (3) and adding ''; or'' in its place; and
■ b. Adding paragraph (4).

The revisions and additions read as follows:

§ 71.2 Definitions.

* * * * *

Regulated pollutant (for fee calculation), which is used only for purposes of § 71.9(c), means any ''*regulated air pollutant''* except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

■ 9. Section 71.9 is amended by:
■ a. Revising paragraphs (c)(1), (c)(2)(i), (c)(3), and (c)(4); and
■ b. Adding paragraph (c)(8).

The revisions and addition read as follows:

§ 71.9 Permit fees.

* * * * *

(c) * * *

(1) For part 71 programs that are administered by EPA, each part 71 source shall pay an annual fee which is the sum of:

(i) $32 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(ii) Any GHG fee adjustment required under paragraph (c)(8) of this section.

(2) * * *

(i) Where the EPA has not suspended its part 71 fee collection pursuant to paragraph (c)(2)(ii) of this section, the annual fee for each part 71 source shall be the sum of:

(A) $24 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(B) Any GHG fee adjustment required under paragraph (c)(8) of this section.

* * * * *

(3) For part 71 programs that are administered by EPA with contractor assistance, the per ton fee shall vary depending on the extent of contractor involvement and the cost to EPA of contractor assistance. The EPA shall establish a per ton fee that is based on the contractor costs for the specific part 71 program that is being administered, using the following formula:

Cost per ton = $(E \times 32) + [(1 - E) \times \$C]$

Where E represents EPA's proportion of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, $1 - E$ represents the contractor's effort, and C represents the contractor assistance cost on a per ton basis. C shall be computed by using the following formula:

$C = [B + T + N]$ divided by 12,300,000

Where B represents the base cost (contractor costs), where T represents travel costs, and where N represents nonpersonnel data management and tracking costs. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

(4) For programs that are delegated in part, the fee shall be computed using the following formula:

Cost per ton = $(E \times 32) + (D \times 24) + [(1 - E - D) \times \$C]$

Where E and D represent, respectively, the EPA and delegate agency proportions of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, $1 - E - D$ represents the contractor's effort, and C represents the contractor assistance cost on a per ton basis. C shall be computed using the formula for contractor assistance cost found in paragraph (c)(3) of this section and shall be zero if contractor assistance is not utilized. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

* * * * *

(8) *GHG fee adjustment.* The annual fee shall be increased by a GHG fee adjustment for any source that has initiated an activity listed in the following table since the fee was last paid. The GHG fee adjustment shall be equal to the set fee provided in the table for each activity that has been initiated since the fee was last paid:

Activity	Set fee
GHG completeness determination (for initial permit or updated application)	$2,236
GHG evaluation for a permit modification or related permit action	364
GHG evaluation at permit renewal	520

* * * * *

PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 10. The authority citation for part 98 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 11. Section 98.426 is amended by adding paragraph (h) to read as follows:

§ 98.426 Data reporting requirements.

* * * * *

(h) If you capture a CO_2 stream from an electricity generating unit that is subject to subpart D of this part and transfer CO_2 to any facilities that are subject to subpart RR of this part, you must:

(1) Report the facility identification number associated with the annual GHG report for the subpart D facility;

(2) Report each facility identification number associated with the annual GHG reports for each subpart RR facility to which CO_2 is transferred; and

(3) Report the annual quantity of CO_2 in metric tons that is transferred to each subpart RR facility.

■ 12. Section 98.427 is amended by adding paragraph (d) to read as follows:

§ 98.427 Records that must be retained.

* * * * *

(d) Facilities subject to § 98.426(h) must retain records of CO_2 in metric tons that is transferred to each subpart RR facility.

[FR Doc. 2015–22837 Filed 10–22–15; 8:45 am]

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Part II

Environmental Protection Agency

40 CFR Parts 60 and 63

Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2010–0682; FRL–9935–40–OAR]

RIN 2060–AQ75

Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes the residual risk and technology review conducted for the Petroleum Refinery source categories regulated under national emission standards for hazardous air pollutants (NESHAP) Refinery MACT 1 and Refinery MACT 2. It also includes revisions to the Refinery MACT 1 and MACT 2 rules in accordance with provisions regarding establishment of MACT standards. This action also finalizes technical corrections and clarifications for the new source performance standards (NSPS) for petroleum refineries to improve consistency and clarity and address issues related to a 2008 industry petition for reconsideration. Implementation of this final rule will result in projected reductions of 5,200 tons per year (tpy) of hazardous air pollutants (HAP) which will reduce cancer risk and chronic health effects.

DATES: This final action is effective on February 1, 2016. The incorporation by reference of certain publications for part 63 listed in the rule is approved by the Director of the Federal Register as of February 1, 2016. The incorporation by reference of certain publications for part 60 listed in the rule were approved by the Director of the Federal Register as of June 24, 2008.

ADDRESSES: The Environmental Protection Agency (EPA) has established a docket for this action under Docket ID No. EPA–HQ–OAR–2010–0682. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, 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 either electronically through *http://www.regulations.gov*, or in hard copy 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 Air and Radiation Docket and Information Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact Ms. Brenda Shine, Sector Policies and Programs Division, Refining and Chemicals Group (E143–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, 27711; telephone number: (919) 541–3608; fax number: (919) 541–0246; and email address: *shine.brenda@epa.gov.* For specific information regarding the risk modeling methodology, contact Mr. Ted Palma, Health and Environmental Impacts Division (C539–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5470; fax number: (919) 541–0840; and email address: *palma.ted@epa.gov.* For information about the applicability of the NESHAP to a particular entity, contact Ms. Maria Malave, Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, William Jefferson Clinton Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 564–7027; fax number: (202) 564–0050; and email address: *malave.maria@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble Acronyms and Abbreviations. 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:

10/25 tpy	emissions equal to or greater than 10 tons per year of a single pollutant or 25 tons per year of cumulative pollutants
AEGL	acute exposure guideline levels
APCD	air pollution control devices
API	American Petroleum Institute
BAAQMD	Bay Area Air Quality Management District
BDT	best demonstrated technology
BLD	bag leak detectors
BSER	best system of emission reductions
Btu/ft^2	British thermal units per square foot
Btu/scf	British thermal units per standard cubic foot
CAA	Clean Air Act
CBI	confidential business information
CCU	catalytic cracking units
CDX	Central Data Exchange
CEDRI	Compliance and Emissions Data Reporting Interface
CEMS	continuous emission monitoring system
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
COMS	continuous opacity monitoring system
COS	carbonyl sulfide
CPMS	continuous parameter monitoring system
CRA	Congressional Review Act
CRU	catalytic reforming units
CS_2	carbon disulfide
DCU	delayed coking units
EPA	Environmental Protection Agency
ERPG	emergency response and planning guidelines
ERT	Electronic Reporting Tool
ESP	electrostatic precipitator
FCCU	fluid catalytic cracking unit
FGCD	fuel gas combustion device
FMP	flare management plan
FR	Federal Register
FTIR	Fourier transform infrared spectroscopy
GC	gas chromatograph
GHG	greenhouse gases
H_2S	hydrogen sulfide
HAP	hazardous air pollutants
HCl	hydrogen chloride
HCN	hydrogen cyanide
HF	hydrogen fluoride
HFC	highest fenceline concentration
HI	hazard index
HQ	hazard quotient
ICR	information collection request
IRIS	Integrated Risk Information System
km	kilometers
LAER	lowest achievable emission rate
lb/day	pounds per day
LDAR	leak detection and repair
LEL	lower explosive limit
LTD	long tons per day
MACT	maximum achievable control technology
MIR	maximum individual risk
mph	miles per hour
MPV	miscellaneous process vent
NAICS	North American Industry Classification System
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NFS	near-field interfering source
NHVCZ	combustion zone net heating value
Ni	nickel
NO_X	nitrogen oxides
NRDC	Natural Resources Defense Council
NSPS	new source performance standards
NTTAA	National Technology Transfer and Advancement Act
OAQPS	Office of Air Quality Planning and standards
OECA	Office of Enforcement and Compliance Assurance
OEHHA	Office of Environmental Health Hazard Assessment
OEL	open-ended line
OMB	Office of Management and Budget
PM	particulate matter
$PM_{2.5}$	particulate matter 2.5 micrometers in diameter and smaller
ppbv	parts per billion by volume
ppm	parts per million

ppmv	parts per million by volume
PRA	Paperwork Reduction Act
PRD	pressure relief device [1]
psia	pounds per square inch absolute
psig	pounds per square inch gauge
REL	reference exposure level
REM Model	Refinery Emissions Model
RFA	Regulatory Flexibility Act
RTC	response to comment
RTR	Risk and Technology Review
SAB	Science Advisory Board
SBA	Small Business Administration
SCAQMD	South Coast Air Quality Management District
SCR	selective catalytic reduction
SISNOSE	significant economic impact on a substantial number of small entities
SO$_2$	sulfur dioxide
SRP	sulfur recovery plant
SRU	sulfur recovery unit
SSM	startup, shutdown and malfunction
TOSHI	target organ-specific hazard index
tpy	tons per year
UMRA	Unfunded Mandates Reform Act
URE	unit risk estimate
UV–DOAS	ultraviolet differential optical absorption spectroscopy
VCS	voluntary consensus standards
VOC	volatile organic compounds
°F	degrees Fahrenheit
ΔC	the concentration difference between the highest measured concentration and the lowest measured concentration
μg/m^3	micrograms per cubic meter

Background Information. On June 30, 2014, the EPA proposed revisions to both of the petroleum refinery NESHAP based on our residual risk and technology review (RTR). In that action, we also proposed to revise the NESHAP pursuant to CAA section 112(d)(2) and (3), to revise the SSM provisions in the NESHAP, and to make technical corrections to the NSPS to address issues related to reconsideration of the final NSPS subpart Ja rule in 2008. In this action, we are finalizing decisions and revisions for these rules. We summarize some of the more significant comments received regarding the proposed rule and provide our responses in this preamble. A summary of all other public comments on the proposal and the EPA's responses to those comments is provided in the ''Response to Comment'' document, which is available in Docket ID No. EPA–HQ–OAR–2010–0682. The ''track changes'' version of the regulatory language that incorporates the changes in this final action is also available in the docket for this rulemaking.

Organization of this Document. This preamble is organized as follows:

I. General Information

A. Does this action apply to me?

Regulated Entities. Categories and entities potentially regulated by this action are shown in Table 1 of this preamble.

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS FINAL ACTION

NESHAP and source category	NAICS [a] Code
Petroleum Refining Industry	324110

[a] North American Industry Classification System.

Table 1 of this preamble is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by the final action for the source categories listed. To determine whether your facility is affected, you should examine the applicability criteria in the appropriate NESHAP or NSPS. If you have any questions regarding the applicability of any aspect of these NESHAP or NSPS, please contact the appropriate person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section of this preamble.

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 will also be available on the Internet through the Technology Transfer Network (TTN) Web site, a forum for information and technology exchange in various areas of air pollution control. Following signature by the EPA Administrator, the EPA will post a copy of this final action at: *http://www.epa.gov/ttn/atw/petref.html.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version and key technical documents at this same Web site.

Additional information is available on the RTR Web site at *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html.* This information includes an overview of the RTR program, links to project Web sites

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[1] This term is common vernacular to describe the variety of devices regulated as pressure relief valves subject to the requirements in 40 CFR part 63 subpart CC.

for the RTR source categories, and detailed emissions and other data we used as inputs to the risk assessments.

C. Judicial Review and Administrative Reconsideration

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 February 1, 2016. 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.

Section 307(d)(7)(B) of the CAA 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 reconsider the rule ''[i]f the person raising an objection can demonstrate to the Administrator 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 should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, WJC 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. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Background

A. What is the statutory authority for this action?

1. NESHAP

Section 112 of the CAA establishes a two-stage regulatory process to address emissions of hazardous air pollutants (HAP) from stationary sources. In the first stage, we must identify categories of sources emitting one or more of the HAP listed in CAA section 112(b) and then promulgate technology-based NESHAP for those sources. ''Major sources'' are those that emit, or have the potential to emit, any single HAP at a rate of 10 tons per year (tpy) or more, or 25 tpy or more of any combination of HAP. For major sources, these standards are commonly referred to as maximum achievable control technology (MACT) standards and must reflect the maximum degree of emission reductions of HAP achievable (after considering cost, energy requirements, and non-air quality health and environmental impacts). In developing MACT standards, CAA section 112(d)(2) directs the EPA to consider the application of measures, processes, methods, systems or techniques, including but not limited to those that reduce the volume of or eliminate HAP emissions through process changes, substitution of materials, or other modifications; enclose systems or processes to eliminate emissions; collect, capture, or treat HAP when released from a process, stack, storage, or fugitive emissions point; are design, equipment, work practice, or operational standards; or any combination of the above.

For these MACT standards, the statute specifies certain minimum stringency requirements, which are referred to as MACT floor requirements, and which may not be based on cost considerations. See CAA section 112(d)(3). For new sources, the MACT floor cannot be less stringent than the emission control achieved in practice by the best-controlled similar source. The MACT standards for existing sources can be less stringent than floors for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12-percent of existing sources in the category or subcategory (or the best-performing 5 sources for categories or subcategories with fewer than 30 sources). In developing MACT standards, we must also consider control options that are more stringent than the floor, under CAA section 112(d)(2). We may establish standards more stringent than the floor, based on the consideration of the cost of achieving the emissions reductions, any non-air quality health and environmental impacts, and energy requirements.

In the second stage of the regulatory process, the CAA requires the EPA to undertake 2 different analyses, which we refer to as the technology review and the residual risk review. Under the technology review, we must review the technology-based standards and revise them ''as necessary (taking into account developments in practices, processes, and control technologies)'' no less frequently than every eight years, pursuant to CAA section 112(d)(6). Under the residual risk review, we must evaluate the risk to public health remaining after application of the technology-based standards and revise the standards, if necessary, to provide an ample margin of safety to protect public health or to prevent, taking into consideration costs, energy, safety and other relevant factors, an adverse environmental effect. The residual risk review is required within eight years after promulgation of the technology-based standards, pursuant to CAA section 112(f). In conducting the residual risk review, if the EPA determines that the current standards provide an ample margin of safety to protect public health, it is not necessary to revise the MACT standards pursuant to CAA section 112(f).[2] For more information on the statutory authority for this rule, see 79 FR 36879.

2. NSPS

Section 111 of the CAA establishes mechanisms for controlling emissions of air pollutants from stationary sources. Section 111(b) of the CAA provides authority for the EPA to promulgate NSPS that apply only to newly constructed, reconstructed and modified sources. Once the EPA has elected to set NSPS for new and modified sources in a given source category, CAA section 111(d) calls for regulation of existing sources, with certain exceptions explained below.

Specifically, section 111(b) of the CAA requires the EPA to establish emission standards for any category of new and modified stationary sources that the Administrator, in his or her judgment, finds ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' The EPA has previously made endangerment findings under this section of the CAA for more than 60 stationary source categories and subcategories that are now subject to NSPS.

Section 111 of the CAA gives the EPA significant discretion to identify the affected facilities within a source category that should be regulated. To define the affected facilities, the EPA can use size thresholds for regulation and create subcategories based on source type, class or size. Emission limits also may be established either for equipment within a facility or for an entire facility. For listed source categories, the EPA must establish ''standards of performance'' that apply

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[2] The U.S. Court of Appeals has affirmed this approach of implementing CAA section 112(f)(2)(A): *NRDC* v. *EPA*, 529 F.3d 1077, 1083 (D.C. Cir. 2008) (''If EPA determines that the existing technology-based standards provide an 'ample margin of safety,' then the Agency is free to readopt those standards during the residual risk rulemaking.'').

to sources that are constructed, modified or reconstructed after the EPA proposes the NSPS for the relevant source category.[3]

The EPA also has significant discretion to determine the appropriate level for the standards. Section 111(a)(1) of the CAA provides that NSPS are to 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 non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is commonly referred to as best demonstrated technology (BDT) or the best system of emission reduction (BSER). The standard that the EPA develops, based on the BSER achievable at that source, is commonly a numerical emission limit, expressed as a performance level (*i.e.,* a rate-based standard). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a NSPS. Rather, sources remain free to elect whatever combination of measures will achieve equivalent or greater control of emissions.

Costs are also considered in evaluating the appropriate standard of performance for each category or subcategory. The EPA generally compares control options and estimated costs and emission impacts of multiple, specific emission standard options under consideration. As part of this analysis, the EPA considers numerous factors relating to the potential cost of the regulation, including industry organization and market structure, control options available to reduce emissions of the regulated pollutant(s) and costs of these controls.

B. How do the NESHAP and NSPS regulate air pollutant emissions from refineries?

The EPA promulgated the petroleum refinery NESHAP pursuant to CAA section 112(d)(2) and (3) for refineries located at major sources in two separate rules. On August 18, 1995, the first petroleum refinery MACT standard was promulgated in 40 CFR part 63, subpart CC (60 FR 43620). This rule is known as ''Refinery MACT 1'' and covers the ''Sources Not Distinctly Listed,'' meaning it includes all emissions sources from petroleum refinery process units, except those listed separately under the section 112(c) source category list and expected to be regulated by other MACT standards (for example, boilers and process heaters). Some of the emission sources regulated in Refinery MACT 1 include miscellaneous process vents (MPV), storage vessels, wastewater, equipment leaks, gasoline loading racks, marine tank vessel loading and heat exchange systems.

On April 11, 2002 (67 FR 17762), EPA promulgated a second MACT standard regulating certain process vents that were listed as a separate source category under CAA section 112(c) and that were not addressed as part of the Refinery MACT 1. This standard, which is referred to as ''Refinery MACT 2'', covers process vents on catalytic cracking units (CCU) (including FCCU), CRU and SRU and is codified as 40 CFR part 63, subpart UUU.

Finally, on October 28, 2009, we revised Refinery MACT 1 by adding MACT standards for heat exchange systems, which the EPA had not addressed in the original 1995 Refinery MACT 1 rule (74 FR 55686). In this same 2009 action, we updated the cross-references to the General Provisions in 40 CFR part 63. On June 20, 2013 (78 FR 37133), we promulgated minor revisions to the heat exchange provisions of Refinery MACT 1.

On September 27, 2012, Air Alliance Houston, California Communities Against Toxics and other environmental and public health groups filed a lawsuit alleging that the EPA missed statutory deadlines to review and revise Refinery MACT 1 and 2. The EPA reached an agreement to settle that litigation and entered into a Consent Decree. The Consent Decree provides for the Administrator to sign a final action no later than September 30, 2015.

Refinery NSPS subparts J and Ja regulated criteria pollutant emissions, including particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_X) and carbon monoxide (CO) from FCCU catalyst regenerators, fuel gas combustion devices (FGCD) and sulfur recovery plants. Refinery NSPS subpart Ja also regulates criteria pollutant emissions from fluid coking units and DCU.

The NSPS for petroleum refineries (40 CFR part 60, subpart J) were promulgated in 1974, amended in 1976 and amended again in 2008, following a review of the standards. As part of the review that led to the 2008 amendments to the Refinery NSPS subpart J, the EPA developed separate standards of performance for new process units (40 CFR part 60, subpart Ja). However, the EPA received multiple petitions for reconsideration on issues related to those standards. The Administrator granted the petitions for reconsideration. The EPA addressed petition issues related to process heaters and flares by promulgating amendments to the Refinery NSPS subparts J and Ja on September 12, 2012 (77 FR 56422). In this action, we are finalizing technical corrections and clarifications to NSPS subparts J and Ja raised by American Petroleum Institute (API) in their 2008 petition for reconsideration that were not addressed by the final NSPS amendments of 2012.

The petroleum refining industry consists of facilities that engage in converting crude oil into refined products, including liquefied petroleum gas, gasoline, kerosene, aviation fuel, diesel fuel, fuel oils, lubricating oils and feedstocks for the petrochemical industry. Currently, 142 facilities have emission sources regulated by either or both Refinery MACT 1 and 2.

Petroleum refinery activities start with the receipt of crude oil for storage at the refinery, include all the petroleum handling and refining operations, and terminate with loading of refined products into pipelines, tank or rail cars, tank trucks, or ships or barges that take products from the refinery to distribution centers. Petroleum-specific process units include FCCU and CRU. Other units and processes found at petroleum refineries (as well as at many other types of manufacturing facilities) include storage vessels and wastewater treatment plants. HAP emitted by this industry include organics (*e.g.,* acetaldehyde, benzene, formaldehyde, hexane, phenol, naphthalene, 2-methylnaphthalene, dioxins, furans, ethyl benzene, toluene and xylene); reduced sulfur compounds (*i.e.,* carbonyl sulfide (COS), carbon disulfide (CS2))); inorganics (*e.g.,* hydrogen chloride (HCl), hydrogen cyanide (HCN), chlorine, hydrogen fluoride (HF)); and metals (*e.g.,* antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, mercury, manganese and nickel (Ni)). This industry also emits criteria pollutants and other non-HAP, including NO_X, PM, SO_2, volatile organic compounds (VOC), CO, greenhouse gases (GHG) and total reduced sulfur.

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[3] Specific statutory and regulatory provisions define what constitutes a modification or reconstruction of a facility. 40 CFR 60.14 provides that an existing facility is modified and, therefore, subject to an NSPS, if it undergoes any physical change in the method of operation 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. 40 CFR 60.15, in turn, provides that a facility is reconstructed if components are replaced at an existing facility to such an extent that the capital cost of the new equipment/components exceed 50-percent of what is believed to be the cost of a completely new facility.

C. What changes did we propose for the Petroleum Refinery NESHAP and NSPS in our June 30, 2014, RTR proposal?

On June 30, 2014, the EPA published a proposed rule in the **Federal Register** addressing the RTR for the Petroleum Refinery NESHAP, 40 CFR part 63, subparts CC and UUU. The proposal also included changes pursuant to section 112(d)(2) and (3) and technical revisions to the NSPS. Specifically, we proposed:

(1) Pursuant to CAA sections 112(d)(2) and (3):

a. *Refinery MACT 1:*

- Adding MACT Standards for DCU decoking operations.
- Adding operational requirements for flares used as APCD in Refinery MACT 1 and 2.
- Adding requirements and clarifications for vent control bypasses in Refinery MACT 1.

b. *Refinery MACT 2:*

- Revising the CRU purge vent exemption.

(2) Pursuant to CAA sections 112(d)(6) and 112(f)(2):

- Revising Refinery MACT 1 to cross-reference the corresponding storage vessel requirements in the Generic MACT (40 CFR part 63, subpart WW, as applicable), and revising the definition of Group 1 storage vessels to include smaller capacity storage vessels and to include storage vessels storing materials with lower vapor pressures.

(3) Pursuant to CAA section 112(d)(6):

a. *Refinery MACT 1:*

- Allowing refineries to meet the leak detection and repair (LDAR) requirements in Refinery MACT 1 by monitoring for leaks using optical gas imaging in place of EPA Method 21, once the monitoring protocol set forth in Appendix K is promulgated.
- Amending the Marine Tank Vessel Loading Operations NESHAP, 40 CFR part 63, subpart Y, to delete the exclusion for marine vessel loading operations at petroleum refineries.
- Establishing a fenceline monitoring work practice standard to improve the management of fugitive emissions.

b. *Refinery MACT 2:*

- Incorporating requirements consistent with those in Refinery NSPS subpart Ja for FCCU including:
- Requiring the use of 3-hour averages rather than daily averages for parameter operating limits (*e.g.,* depending on the type of control device: Opacity, total power, secondary current, pressure drop, and/or liquid-to-gas ratio).
- Removing the Refinery NSPS subpart J incremental PM emissions allowance for post combustion devices when burning liquid or solid fuels, and removing the 30 percent opacity limit for units complying with NSPS subpart J.
- Adding requirements for FCCU controls to include bag leak detectors (BLD) as an option to continuous opacity monitoring system (COMS).
- Incorporating total power and the secondary current operating limits for electrostatic precipitators (ESP).
- Requiring daily checks of the air or water pressure to the spray nozzles on jet ejector-type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles.
- Requiring FCCU periodic performance testing on a frequency of once every 5 years, as opposed to the current rule, which only requires an initial performance test.
- Including a correlation equation for the use of oxygen-enriched air for SRU.
- Allowing SRU subject to Refinery NSPS subpart Ja with a capacity greater than 20 long tons per day (LTD) to comply with Refinery NSPS subpart Ja as a means of complying with Refinery MACT 2.

(4) Other proposed changes include:

- Removing exemptions from the rule requirements for periods of SSM in order to ensure that the NESHAP are consistent with the court decision in *Sierra Club* v. *EPA,* 551 F. 3d 1019 (D.C. Cir. 2008).
- Clarifying requirements related to open-ended valves or lines.
- Adding electronic reporting requirements.
- Updating the General Provisions cross-reference tables.
- Making technical corrections and clarifications to NSPS subparts J and Ja.

III. What is included in this final rule?

This action finalizes the EPA's determinations pursuant to the RTR provisions of CAA section 112 for the Petroleum Refinery source categories and amends the Petroleum Refinery NESHAP based on those determinations. This action also finalizes other changes to the NESHAP including revising Refinery MACT 1 and 2 pursuant to CAA section 112 (d)(2) and (3), including revising requirements for flares and pressure relief devices (PRD). This action finalizes changes to the SSM provisions to ensure that the subparts are consistent with the court decision in *Sierra Club* v. *EPA,* 551 F. 3d 1019 (D.C. Cir. 2008), adds electronic reporting requirements in Refinery MACT 1 and 2; and updates the General Provisions cross-reference tables. Finally, this action finalizes technical corrections and clarifications to Refinery NSPS subparts J and Ja to address issues raised in the reconsideration of these rules.

A. What are the final NESHAP amendments based on the risk review for the Petroleum Refinery source categories?

The EPA is promulgating final amendments to the Petroleum Refinery NESHAP pursuant to CAA section 112(f) that expand the existing Refinery MACT 1 control requirements and extend these requirements to smaller tanks and tanks with lower vapor pressures. Specifically, consistent with the proposal, the EPA is amending Refinery MACT 1 by revising the definition of Group 1 storage vessels to include storage vessels with capacities greater than or equal to 20,000 gallons but less than 40,000 gallons if the maximum true vapor pressure is 1.0 psia or greater and to include storage tanks greater than 40,000 gallons if the maximum true vapor pressure is 0.75 psia or greater. The EPA is also adding a cross-reference to the storage vessel requirements in the Generic MACT (40 CFR part 63, subpart WW and subpart CC), which include requirements for guide pole controls and other fittings as well as inspection requirements. After considering the public comments, the final amendments include minor changes from our proposed requirements to clarify language and correct typographical and referencing errors.

B. What are the final NESHAP amendments based on the technology review for the Petroleum Refinery source categories?

1. Refinery MACT 1

We determined that there are developments in practices, processes and control technologies that warrant revisions to the MACT standards for this source category. Therefore, to satisfy the requirements of CAA section 112(d)(6), we are revising the MACT standards to amend 40 CFR part 63, subpart Y to delete the exclusion for marine vessel loading operations at petroleum refineries. Removing this exclusion will require small marine vessel loading operations (*i.e.,* operations with HAP emissions less than 10/25 tpy) and offshore marine vessel loading operations to use submerged filling based on the cargo filling line requirements in 46 CFR 153.282, as proposed.

We are also finalizing a fenceline monitoring work practice standard to improve the management of fugitive emissions and finalizing EPA Methods 325A and 325B to support the work practice, with some changes from proposal to address issues raised by commenters. Key revisions include: New provisions for reduced monitoring for facilities with consistently low fenceline concentrations; requirements for alternatives to passive monitoring; revised placement guidance to allow perimeter monitoring within a facility's property boundary provided all sources are encompassed within the monitoring perimeter; reductions in the number of monitors required for subareas and segregated areas; clarifications on monitor placement for internal roadways or other right-of-ways and marine docks; and revised timelines for submitting periodic reports (quarterly rather than semiannually) and implementing the work practice standard (2 years after promulgation rather than 3 years as proposed). We are also revising Refinery MACT 1 storage vessel requirements as described above under the risk review, as proposed.

2. Refinery MACT 2

We determined that there are developments in practices, processes and control technologies that warrant revisions to the MACT standards for this source category. Therefore, to satisfy the requirements of CAA section 112(d)(6), we are revising the Refinery MACT 2 standard for FCCU subject to Refinery NSPS subpart J or those electing to comply with the Refinery NSPS subpart J requirements. As proposed, we are removing the incremental PM limit when burning liquid or solid fuels. We are finalizing a 20-percent opacity operating limit evaluated on a 3-hour average, which differs from the proposal to eliminate the 30-percent opacity limit and instead allow only for a site-specific opacity operating limit or control device parameter monitoring. As proposed, we are finalizing requirements to make Refinery MACT 2 consistent with Refinery NSPS subpart Ja for FCCU by including 3-hour averages rather than daily averages for parameter operating limits, and by including 3-hour averages rather than daily averages for the site-specific opacity operating limit. We are also finalizing requirements, as proposed, for FCCU controls to include adding BLD as an option to COMS, incorporating total power and the secondary current operating limits for ESP and requiring daily checks of the air or water pressure to the spray nozzles on jet ejector-type wet scrubbers or other types of wet scrubbers equipped with atomizing spray nozzles.

Finally, we are finalizing, as proposed, requirements for FCCU periodic performance testing at a frequency of once every 5 years rather than the current requirements for a one-time initial performance test. However, for owners or operators complying with the Refinery NSPS subpart J option (with the 20-percent opacity operating limit discussed above), if the PM emissions are within 80-percent of the PM limit during any periodic performance test (*i.e.,* emissions exceed 0.8 lb PM/1,000 lbs of coke burn-off), the refinery owner or operator must conduct subsequent performance tests on an annual basis. Based on comments received, we are also adding requirements in the final rule for owners or operators of FCCU to conduct a one-time test for HCN emissions from the FCCU concurrent with their first periodic performance test, which must be conducted on or before August 1, 2017 for all FCCU subject to Refinery MACT 2.

For SRU, as proposed, we are finalizing a correlation equation for the use of oxygen-enriched air. Additionally, as proposed, we are finalizing requirements to allow sulfur recovery plants subject to Refinery NSPS subpart Ja with a capacity greater than 20 LTD to comply with Refinery NSPS subpart Ja as a means of complying with Refinery MACT 2.

C. What are the final NESHAP amendments pursuant to section 112(d)(2) & (3) for the Petroleum Refinery source categories?

1. Refinery MACT 1

We are finalizing MACT standards for DCU decoking operations that require that each coke drum be depressured to a closed blowdown system until the coke drum pressure is 2 psig with minor revisions from proposal. Specifically, we are finalizing provisions for existing DCU affected sources to average over a 60-cycle (*i.e.,* 60 batch) basis to comply with the 2 psig limit, rather than the proposed requirement to meet the 2 psig limit on a per venting event basis. In addition, we are finalizing requirements for new DCU affected sources to depressure to 2.0 psig on a per-event, not-to-exceed basis, adding one significant digit to the limit for new DCU affected sources. For both new and existing DCU affected sources, we are finalizing specific provisions for DCU with water overflow design and for double quenching.

We are finalizing operational requirements and the associated monitoring, recordkeeping and reporting requirements for flares used as APCD in Refinery MACT 1 and 2 with revisions to the requirements proposed. Prior to these amendments, Refinery MACT 1 and 2 cross-referenced the General Provisions requirements at 40 CFR 63.11(b). As proposed, this final action replaces the cross reference to the General Provisions and incorporates enhanced flare operational requirements directly into the Refinery MACT regulations. As proposed, the final rule amendments require that refinery flares operate with continuously lit pilot flames at all times. Consistent with our proposal, we are finalizing requirements for flares to operate with no visible emissions and comply with consolidated requirements related to flare tip velocity, but in the final rule these direct emissions limits apply when flare vent gas flow is below the smokeless capacity of the flare rather than at all times. Above the smokeless capacity of the flare, we are establishing a work practice standard related to the visible emissions and velocity limits; these work practice standards are described in more detail in section III.D.1 of this preamble.

We are finalizing new operational requirements related to combustion zone gas properties with revisions from proposal. In response to comments on the proposal, we are finalizing requirements that flares meet a minimum operating limit of 270 BTU/scf NHV_{cz} on a 15-minute average, and are allowing refinery owners or operators to use a corrected heat content of 1,212 BTU/scf for hydrogen to demonstrate compliance with this operating limit. We had proposed two separate sets of limits, one being more stringent if an olefins/hydrogen mixture was present in the waste gas. For each set of limits, we proposed three different alternative combustion zone operating limits: One based on the combustion zone net heat content with no correction for the heat content of hydrogen, one based on the lower flammability limit and one based on the combustibles concentration. We proposed that these limits be determined on a 15-minute ''feed-forward'' block average approach (*i.e.,* compositional data are collected every 15 minutes, after which adjustments are made). We have included an additional option for refiners to comply where more frequent data are collected (using direct net heating value monitoring) to calculate the combustion limit using net heating value data from the same 15-minute block period. We are simplifying the compliance approach to a single operating limit based only on the combustion zone net heating value (with a hydrogen correction). As proposed, we are requiring refinery owners or operators to characterize the composition of waste gas, assist gas and fuel to demonstrate compliance with the operational requirements.

As proposed, we are also finalizing in this rule a burden reduction option to use grab sampling every 8 hours rather than continuous vent gas composition or heat content monitors. We are also including, based on public comment, provisions to conduct limited initial sampling and process knowledge to characterize flare gas composition for flares in ''dedicated'' service as an alternative to collecting grab samples during each specific event. We are finalizing a requirement for daily visible emissions observations as proposed, but, based on public comment, we are allowing owners or operators to use video surveillance cameras to demonstrate compliance with the visible emissions limit as an alternative to the daily visible emissions observations.

For PRD, we are finalizing requirements for monitoring systems that are capable of identifying and recording the time and duration of each pressure release to the atmosphere, as proposed. Certain PRD with low set pressures or low emission potential or in liquid service would not be subject to these monitoring requirements. We are finalizing requirements to minimize or prevent atmospheric releases of HAP through PRD. Instead of the proposed prohibition on such releases, we are finalizing work practice requirements that require both preventive measures as well as root cause analysis and corrective action that will incentivize refinery owners or operators to eliminate the causes of the releases.

We are finalizing requirements for bypass lines with minor revisions from those proposed. Specifically, we are not adopting the proposed requirement to install quantitative flow monitors and thus are leaving in place the requirement to use flow indicators on bypass lines. In addition, we are maintaining the requirements to estimate and report the quantity of organic HAP released. In response to public comment, we are also clarifying changes to remove the proposed reference to air intrusion and specifying that reporting of bypasses is only required when ''regulated material'' is discharged to the atmosphere as a result of a bypass of a control device.

We are also finalizing revisions to the definition of miscellaneous process vent, as proposed. These revisions include deletion of exclusions associated with episodic releases and vents from in situ sampling systems. As proposed, the final amendments require that these vents must meet the standards applicable to MPV.

2. Refinery MACT 2

For CRU vents, we are finalizing the vessel pressure limit exclusion of 5 psig to apply only to passive depressurization, as proposed.

D. What are the final NESHAP amendments addressing emissions during periods of SSM?

We are finalizing, as proposed, changes to Refinery MACT 1 and 2 to eliminate the SSM exemption. 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. EPA is revising Table 6 of subpart CC of 40 CFR part 63 and Table 44 to subpart UUU of 40 CFR part 63 (the General Provisions Applicability Tables) to change several references related to requirements that apply during periods of SSM. We also are eliminating or revising certain recordkeeping and reporting requirements related to the eliminated SSM exemptions. We also are removing or modifying inappropriate, unnecessary or redundant language in the absence of the SSM exemption. Further, for certain emission sources in both MACT 1 and 2, we are establishing standards to address emissions during these periods. These are described below.

1. Refinery MACT 1

We are finalizing a work practice standard for PRD that requires refinery owners or operators to establish prevention measures for each PRD in organic HAP service. Under the work practice standard, where a direct release occurs, the refinery is required to perform root cause analysis and implement corrective action. The work practice standard also limits the number of events that a PRD may release to the atmosphere during a 3-year period, as explained further in the section IV.D. of this preamble.

We are also finalizing a work practice standard for emergency flaring events that requires refinery owners or operators to establish prevention measures, including the development of a flare management plan (FMP), and perform root cause analysis and implement corrective action following flaring events during which the velocity of waste gas going to the flare or visible emissions limits (*i.e.,* opacity) at the flare tip are exceeded, and to limit the number of these events allowed in a 3-year period, as explained further in section IV.D. of this preamble. Both of these work practice standards are consistent with the EPA's goal to improve the effectiveness of the rules. These requirements will provide a strong incentive for facilities, over time, to better operate their processes to prevent PRD and flare releases.

We are also finalizing requirements for opening process equipment to the atmosphere during maintenance events after draining and purging to a closed system, provided the hydrocarbon content is less than or equal to 10-percent of the lower explosive limit (LEL). For those situations where 10-percent LEL cannot be demonstrated, the equipment may be opened and vented to the atmosphere if the pressure is less than or equal to 5 psig, provided there is no active purging of the equipment to the atmosphere until the LEL criterion is met. This 5 psig allowance is only available during shutdown. We are also providing additional allowances for situations where it is not technically feasible to depressurize a control system where there is no more than 72 lbs VOC per day vented to the atmosphere, consistent with our Group 1 applicability cutoff for control of process vents, or for catalyst changeout activities where hydrotreater pyrophoric catalyst must be purged. Provisions to demonstrate that process equipment is opened only after the LEL, pressure or mass in the vessel requirement is met includes documenting the procedures for equipment openings and procedures for verifying that the openings meet the specific, above-discussed requirements using site-specific procedures used to de-inventory equipment for safety purposes (*i.e.,* hot work or vessel entry procedures).

2. Refinery MACT 2

The Refinery MACT 2 standards regulate all HAP emissions from the three refinery process vents subject to Refinery MACT 2. For FCCU, the standard specifies a CO limit as a surrogate for organic HAP and specifies a PM limit (or Ni limit) as a surrogate for metal HAP. Compliance with the organic HAP emissions limit is demonstrated using a continuous CO monitor; compliance with the metal HAP emissions limit is demonstrated using either COMS or control device parameter monitoring systems (CPMS). At proposal, with the removal of the exemptions in the Refinery MACT 2 rule for periods of startup and shutdown, we recognized the need for alternative standards during some startup and shutdown situations, and we proposed alternative requirements.

For this final rule, we are including a 1-percent minimum oxygen limit as an alternative to the 500 ppmv hourly CO limit during FCCU startup for partial burn FCCU with CO boilers, as proposed. We are extending that alternative limit to all FCCU and extending it to apply during shutdown.

We are not finalizing the proposed alternative opacity limit for FCCU during startup. Instead, based on public comments received, we are finalizing an alternative minimum cyclone face velocity limit as a means to demonstrate compliance with the PM limit during both startup and shutdown, regardless of the type of FCCU and its control device. We are finalizing alternative standards for sulfur recovery plant (SRP) incinerator temperature and excess oxygen limits during SRP shutdown, as proposed, and we are extending the proposed alternative standards to startup as well.

E. What other revisions to the NESHAP and NSPS are being promulgated?

We are finalizing technical amendments to NSPS subparts J and Ja with limited changes from what we proposed. First, in response to comments, we are revising the NSPS requirements that a flow sensor have a ‘‘measurement sensitivity’’ of no more than 5-percent of the flow rate to an ‘‘accuracy’’ requirement that the flow sensor have an accuracy of 5-percent of the flow rate. This change will make the requirements more clear and consistent between the flow meter requirements in the NSPS and the MACT standards since it is the same flow meter subject to these requirements. We are also revising flare flow rate accuracy requirements in Refinery NSPS subpart Ja to make them consistent with those we are finalizing in Refinery MACT 1. Finally, we are revising 40 CFR 60.101a(b) to begin as ‘‘Except for flares and delayed coking units . . .’’ to correct an inadvertent error. We proposed revisions to this sentence solely to allow sources subject to Refinery NSPS subpart J to comply with the provisions in Refinery NSPS subpart Ja instead. However, the words ‘‘and delayed coking units’’ were inadvertently omitted from the initial part of the sentence. Thus, as intended, we are finalizing revisions to this sentence to allow sources subject to Refinery NSPS subpart J to comply with the provisions in Refinery NSPS subpart Ja.

F. What are the requirements for submission of performance test data to the EPA?

As proposed, the EPA is taking a step to increase the ease and efficiency of data submittal and data accessibility. Specifically, the EPA is finalizing the requirement for owners or operators of Petroleum Refinery facilities to submit electronic copies of certain required performance test reports through the EPA’s Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). The EPA believes that the electronic submittal of the reports addressed in this rulemaking will increase the usefulness of the data contained in those reports, is in keeping with current trends in data availability, will further assist in the protection of public health and the environment and will ultimately result in less burden on the regulated community. Electronic reporting can also eliminate paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing data reporting errors and providing data quickly and accurately to the affected facilities, air agencies, the EPA and the public.

As mentioned in the preamble of the proposal, the EPA Web site that stores the submitted electronic data, WebFIRE, will be easily accessible to everyone and will provide a user-friendly interface that any stakeholder could access. By making the records, data and reports addressed in this rulemaking readily available, the EPA, the regulated community and the public will benefit when the EPA conducts its CAA-required technology and risk-based reviews. As a result of having reports readily accessible, our ability to carry out comprehensive reviews will be increased and achieved within a shorter period of time.

We anticipate fewer or less substantial information collection requests (ICRs) in conjunction with prospective CAA-required technology and risk-based reviews may be needed. We expect this to result in a decrease in time spent by industry to respond to data collection requests. We also expect the ICRs to contain less extensive stack testing provisions, as we will already have stack test data electronically. Reduced testing requirements would be a cost savings to industry. The EPA should also be able to conduct these required reviews more quickly. While the regulated community may benefit from a reduced burden of ICRs, the general public benefits from the agency’s ability to provide these required reviews more quickly, resulting in increased public health and environmental protection.

Air agencies could benefit from more streamlined and automated review of the electronically submitted data. Having reports and associated data in electronic format will facilitate review through the use of software ‘‘search’’ options, as well as the downloading and analyzing of data in spreadsheet format. The ability to access and review air emission report information electronically will assist air agencies to more quickly and accurately determine compliance with the applicable regulations, potentially allowing a faster response to violations which could minimize harmful air emissions. This benefits both air agencies and the general public.

For a more thorough discussion of electronic reporting required by this rule, see the discussion in the preamble of the proposal. In summary, in addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with performance test data will save industry, air agencies, and the EPA significant time, money, and effort while improving the quality of emission inventories, air quality regulations, and enhancing the public’s access to this important information.

G. What are the effective and compliance dates of the NESHAP and NSPS?

The final amendments to the NESHAP and NSPS in this action are effective on February 1, 2016. As proposed, new sources must comply with these requirements by the effective date of the final rule or upon startup, whichever is later.

As proposed, existing sources are required to comply with the final DCU and CRU requirements no later than 3 years after the effective date of the final rule. Similarly, as proposed, owners or operators are required to comply with the new operating and monitoring requirements for existing flares no later than 3 years after the effective date of the final rule.

We proposed to provide 3 years from the effective date of the final rule for refinery owners or operators to install and begin monitoring (collecting samples) around the fenceline of their existing facility. If refinery owners and operators determined that a site-specific monitoring plan was needed, they would also need to submit and receive approval for such a plan during the 3-year compliance period. Based on information submitted during the comment period, we are finalizing requirements that refinery owners or operators begin collecting samples around the fenceline within 2 years of the effective date of the final rule. Based on information submitted during the comment period, 1 year is sufficient time to identify proper monitoring locations and to install the required monitoring stations around the facility fenceline. However, owners or operators may need additional monitoring systems to account for near-field interfering sources (NFS), for which the development and approval of a site-specific fenceline monitoring plan is required. We expect that the site-specific fenceline monitoring plans can take an additional year to develop, submit and obtain approval. Consequently, we are providing 2 years from the effective date of the final rule for refinery owners or operators to install and begin collecting samples around the fenceline of their facility.

As proposed, we are requiring that existing sources comply with the submerged filling requirement for marine vessel loading on the effective date of the final rule.

As proposed, we are providing 18 months after the effective date of the final rule to conduct required performance tests and comply with any revised operating limits for FCCU.

We proposed to require refinery owners or operators to comply with the revisions to the SSM provisions of Refinery MACT 1 and 2 on the effective date of the final rule. As proposed, this final rule requires refinery owners or operators to comply with the limits in Refinery MACT 2 or the alternative limits in this final rule during startup and shutdown for FCCU and SRU on the effective date of the final rule.

The flare work practice standards for high-load flaring events (events exceeding the smokeless capacity of the flare) require development of FMP (or revision of an existing plan) to specifically consider emergency shutdown and other high load events. In this FMP, refinery owners or operators must consider measures that can be implemented to reduce the frequency and magnitude of these high-load flaring events. This may include installation of a flare gas recovery system. Additionally, the work practice standards will require refinery owners or operators to identify and implement measures that may involve process changes. Therefore, we are establishing a compliance date of 3 years from the effective date of the final rule for refinery owners or operators to comply with the work practice standards for high load flaring events. We also note that this compliance period is consistent with the compliance time provided for the flare operating limits.

For atmospheric PRD in HAP service we are establishing a work practice standard that requires a process hazard analysis and implementation of a minimum of three redundant measures to prevent atmospheric releases. Alternately, refinery owners or operators may elect to install closed vent systems to route these PRD to a flare, drain (for liquid thermal relief valves) or other control system. We anticipate that sources will need to identify the most appropriate preventive measures or control approach; design, install and test the system; install necessary process instrumentation and safety systems; and may need to time installations with equipment shutdown or maintenance outages. Therefore, we have established a compliance date of 3 years from the effective date of the final rule for refinery owners or operators to comply with the work practice standards for atmospheric PRD.

As proposed, we are requiring compliance with the electronic reporting provisions for performance tests conducted for Refinery MACT 1 and 2 on the effective date of the final rule.

Finally, we are finalizing additional requirements for storage vessels under CAA sections 112(d)(6) and (f)(2) with a compliance date 90 days after the effective date of the final rule, as proposed.

H. What materials are being incorporated by reference?

In this final rule, the EPA is including regulatory text that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, the EPA is incorporating by reference the following documents described in the amendments to 40 CFR 63.14:

- ASTM D1945–03 (Reapproved 2010), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, (Approved January 1, 2010).
- ASTM D1945–14, Standard Test Method for Analysis of Natural Gas by Gas Chromatography.
- ASTM D6196–03 (Reapproved 2009), Standard Practice for Selection of Sorbents, Sampling, and Thermal Desorption Analysis Procedures for Volatile Organic Compounds in Air, (Approved March 1, 2009).
- ASTM D6348–03 (Reapproved 2010), Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, including Annexes A1 through A8, (Approved October 1, 2010).
- ASTM D6348–12e1, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy.
- ASTM D6420–99 (Reapproved 2010), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry.
- ASTM UOP539–12, Refinery Gas Analysis by GC.
- BS EN 14662–4:2005, Ambient air quality—Standard method for the measurement of benzene concentrations—Part 4: Diffusive sampling followed by thermal desorption and gas chromatography, June 27, 2005.
- EPA–454/B–08–002, Quality Assurance Handbook for Air Pollution Measurement Systems, Volume IV: Meteorological Measurements, Version 2.0 (Final), March 2008.
- EPA–454/R–99–005, Meteorological Monitoring Guidance for Regulatory Modeling Applications, February 2000.
- ISO 16017–2:2003(E): Indoor, ambient and workplace air—Sampling and analysis of volatile organic compounds by sorbent tube/thermal desorption/capillary gas chromatography—Part 2: Diffusive sampling, May 15, 2003.
- Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources'' Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003.[4]

The EPA has made, and will continue to make, these documents available electronically through *www.regulations.gov* and/or in hard copy at the appropriate EPA office (see the **ADDRESSES** section of this preamble for more information).

IV. What is the rationale for our final decisions and amendments to the Petroleum Refinery NESHAP and NSPS?

A. Residual Risk Review for the Petroleum Refinery Source Categories

1. What did we propose pursuant to CAA section 112(f) for the Petroleum Refinery source categories?

The results of our residual risk review for the Petroleum Refinery source categories were published in the June 30, 2014 proposal at (79 FR 36934 through 36942), and included assessment of chronic and acute inhalation risk, as well as multipathway and environmental risk, to inform our decisions regarding acceptability and ample margin of safety. The results indicated that both the actual and

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[4] The requirements in § 63.655(i)(5)(iii)(G) associated with this incorporation by reference have not changed, but are being modified to properly be incorporated into § 63.14(s).

allowable inhalation cancer risks to the individual most exposed are no greater than approximately 100-in-1 million, which is the presumptive limit of acceptability. In addition, the maximum chronic non-cancer target organ-specific hazard index (TOSHI) due to inhalation exposures was less than 1. The evaluation of acute non-cancer risks, which was conservative, showed acute risks below a level of concern. Based on the results of the refined site-specific multipathway analysis, we also concluded that the ingestion cancer risk to the individual most exposed through ingestion is considerably less than 100-in-1 million. In determining risk acceptability, we also evaluated population impacts because of the large number of people living near facilities in the source category. We estimated that 5-million people are exposed to increased cancer risks of greater than 1-in-1 million and 100,000 people are exposed to increased cancer risks of greater than 10-in-1 million, but, as noted previously, no individual is exposed to increased cancer risks of greater than 100-in-1 million. Considering the above information, we proposed that the risks remaining after implementation of the existing NESHAP for the Refinery MACT 1 and 2 source categories is acceptable. However, we noted that the risks based on allowable emissions are at the presumptive limit of acceptable risk, and that a large number of people are exposed to risks of greater than 1-in-1 million, and we solicited comment on whether EPA should conclude that the risk was unacceptable based on the health information before the Agency. We also proposed that the original Refinery MACT 1 and 2 MACT standards, along with the proposed requirements for storage vessels, provide an ample margin of safety to protect public health. Finally, we proposed that it is not necessary to set a more stringent standard to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect.

2. How did the risk review change for the Petroleum Refinery source categories?

As part of the final risk assessment, we conducted a screening level analysis of how the information we received during the public comment period, along with the changes we are making to the proposed rule, would change our proposed risk estimates (More details can be found in the ''Final Residual Risk Assessment for the Petroleum Refining Source Sector'', Docket ID No. EPA–HQ–OAR–2010–0682).

First, we received approximately 20 emissions inventory updates for specific facilities. These updates included revised emission estimates, revised release latitude/longitude locations and other release characteristic revisions. The updates provided evidence that the quantity of HAP emitted at these specific facilities is lower than considered in the risk modeling for the proposed rule. Our assessment of the effects of these changes suggests that the cancer maximum individual risk (MIR) based on actual emissions may be closer to 40-in-1 million, as opposed to 60-in-1 million, as projected at proposal. We did not quantify the reductions in chronic or acute non-cancer risks from these updates. We calculated allowable emissions using the Refinery Emissions Model (REM), which estimates emissions based on each refinery's capacities and throughputs [See discussion at 79 FR 36888, June 30, 2014.] The allowable emission estimates for point and fugitive sources were not specific to a particular latitude/longitude location so we assumed them to release from the centroid of the facility. Therefore, the predicted cancer MIR of approximately 100-in-1 million based on allowable emissions and reported in the proposal risk characterization does not change based on the submitted emissions revisions. We did not quantify changes to other actual risk metrics as part of the screening level analysis (*i.e.*, incidence, populations in risk bins, multipathway and ecological analyses), but we would expect some minor reductions from those presented in the proposed risk characterization.

Second, we are establishing work practice standards in the final rule for PRD releases and emergency flaring events, which under the proposed rule would not have been allowed. Thus, because we did not consider such non-routine emissions under our risk evaluation for the proposed rule, we performed a screening assessment of risk associated with these non-routine events for the final rule. [We provide further details on the screening approach in ''Final Residual Risk Assessment for the Petroleum Refining Source Sector'' in Docket ID No. EPA–HQ–OAR–2010–0682.] We extracted information on these events from the 2011 Petroleum Refinery ICR data that included the process unit identification, mass of emissions, duration of release, and description of the incident. We identified the highest HAP mass releases for both PRDs and flares from these non-routine events. We assumed these HAP emission releases could occur at any facility in the source category. Our analysis suggests that these HAP emissions could increase the MIR based on actual emissions by as much as 2-in-1 million. Because the PRD and flaring events were the worst case HAP mass emission release events reported in the 2011 Refinery ICR for the source category, we are assuming that actual and allowable risks are no different for these events (*i.e.*, a MIR of 2-in-1 million). A MIR increase of 2-in-1 million attributable to these events, added to our previous estimate for allowable risk at proposal will not appreciably change our proposed determination that the MIR based on allowable emissions are approximately 100-in-1 million. We note that the MIR estimate attributable to these non-routine PRD and flaring events was estimated using a conservative, screening-level assessment, while the MIR estimate at proposal was based on a refined risk assessment. By adding a screening estimate to a refined risk estimate, we are merely defining an upper limit that we expect the combined risks from both the routine and non-routine emissions to be. Similarly, we estimate chronic non-cancer hazard index (HI) values attributable to the additional exposures resulting from non-routine flaring and PRD HAP emissions to be well below 1 ($HI_{immune\text{-}system}$ of 0.007) such that there is no appreciable change in the maximum chronic non-cancer HI of 0.9 estimated at proposal for routine emissions, which was based on neurological effects.

The screening analysis projects that the maximum predicted acute non-cancer risk from non-routine PRD and flare emissions results in a hazard quotient (HQ) based on a recommended reference exposure level limit (REL) of up to 14 from benzene emissions. While the analysis shows that there is a potential for HQs exceeding 1 for benzene, because of the many uncertainties and conservative nature of this screening analysis, the likelihood of such exposure and risk are low. At proposal, we projected a HQ based on the REL for benzene of up to 2 from routine emissions. If we conservatively combine the routine and non-routine emissions analyses, we would expect the potential for HQs based on the REL for benzene to have the potential to increase above 2. However, as projected at proposal, we estimate that the acute HQs calculated using acute exposure guideline levels (AEGL) and emergency response and planning guidelines (ERPG) values for all pollutants including benzene would still be well below 1 considering both routine and non-routine emissions.

Considering all of these factors, we do not project risks to be significantly different from what we proposed. Based on the risk analysis, as informed by the screening level analysis based on information obtained during the comment period, we are finalizing our determination that the risk remaining after promulgation of the NESHAP is acceptable.

3. What key comments did we receive on the risk review and what are our responses?

We received numerous comments on the residual risk assessment analyses and results. We summarize the key comments received below, along with our responses. A complete summary of all public comments received and our responses are in the ''Response to Comment'' Document in the public docket (Docket ID No. EPA–HQ–OAR–2010–0682).

Comment: Several commenters agreed that the EPA has correctly concluded that the proposed rule requirements protect the public with an ample margin of safety from refinery emissions. Other commenters noted that EPA found residual risks remaining after implementation of the MACT standards to be acceptable, and in light of the acceptability determination argued that the proposed changes to the rule are not justified. The commenters noted that the EPA's detailed emissions inventory assessment and risk modeling results demonstrated that, at every U.S. refinery, category-specific risks are below the EPA's presumptive limit of acceptable risk (*i.e.*, cancer risk of less than 100-in-1 million).

Other commenters stated the EPA's risk estimates are understated and that the EPA should reduce the benchmark of what it considers acceptable lifetime cancer risk instead of the upper limit of 100-in-1 million. One commenter provided an extensive critique of the cancer, chronic and acute affects levels used in the risk assessment and recommended that the EPA use California Office of Environmental Health Hazard Assessment's (OEHHA) new toxicity values for several chemicals. The commenter provided some references for the approaches used to derive the California values. The commenter also asserted that risks would be unacceptable had these more protective values been used in the risk assessment. Some commenters stated the risks from petroleum refinery emissions are underestimated because the EPA did not but should have included interaction of multiple pollutants, accounted for exposure to multiple sources, and assessed the cumulative risks from facility-wide emissions and multiple nearby sources impacting an area.

Response: The approximately 100-in-1 million benchmark was established in the Benzene NESHAP (54 FR 38044, September 14, 1989), which Congress specifically referenced in CAA section 112(f)(2)(B). While this presumptive level provides a benchmark for judging the acceptability of MIR, it is important to recognize that it does not constitute a rigid line for making that determination. The EPA considers the specific uncertainties of the emissions, health effects and risk information for the source category in question when deciding whether the risk posed by that source category is acceptable. In addition, the source category-specific decision of what constitutes an acceptable level of risk is a holistic one; that is, the EPA considers all potential health impacts—chronic and acute, cancer and non-cancer, and multipathway—along with their uncertainties, when determining whether the source category presents an unacceptable risk.

Regarding the comment that in light of the acceptability determination the proposed changes to the rule are not justified, we note that we also are required to ensure that the standards provide an ample margin of safety to protect public health. That analysis is separate from the acceptability analysis, and the determination of acceptability does not automatically lead us to conclude that the standards provide an ample margin of safety to protect public health.

Regarding the comments that the EPA should use the new California OEHHA values, we disagree. The EPA's chemical-specific toxicity values are derived using risk assessment guidelines and approaches that are well established and vetted through the scientific community, and follow rigorous peer review processes.[5] The RTR program gives preference to the EPA values for use in risk assessments and uses other values, as appropriate, when those values are derived with methods and peer review processes consistent with those followed by the EPA. The approach for selecting appropriate toxicity values for use in the RTR Program has been endorsed by the Science Advisory Board (SAB).[6]

The EPA scientists reviewed the information provided by the commenter regarding the California values and concluded that further information is needed to evaluate the scientific basis and rationale for the recent changes in California OEHHA risk assessment methods. The EPA will work on gathering the necessary information to conduct an evaluation of the scientific merit and the appropriateness of the use of California OEHHA's new toxicity values in the agency decisions. Until the EPA has completed its evaluation, it is premature to determine what role these values might play in the RTR process. Therefore, the EPA did not use the new California OEHHA toxicity values as part of this current action. For more detailed responses regarding appropriate reference values for specific pollutants, see the ''Response to Comment'' document in the public docket (Docket ID No. EPA–HQ–OAR–2010–0682).

Concerning comments that we should consider aggregate risks from multiple pollutants and sources, we note that we have done this to the extent it is appropriate to do so. We modeled whole-facility risks for both chronic cancer and non-cancer impacts to understand the risk contribution of the sources within the Petroleum Refinery source categories. The individual cancer risks for the source categories were aggregated for all carcinogens. In assessing non-cancer hazard from chronic exposures to pollutants that have similar modes of action or (where this information is absent) that affect the same target organ, we summed the HQs. This process creates, for each target organ, a TOSHI, defined as the sum of HQs for individual HAP that affect the same organ or organ system. Whole-facility risks were estimated based on the 2011 ICR emissions data obtained from facilities, which included emissions from all sources at the refinery, not just Refinery MACT 1 and 2 emission sources (*e.g.*, emissions were included for combustion units and units subject to the Hazardous Organic NESHAP, if present at the refinery). We disagree with the commenter's assertion that additional quantitative assessment of risks from sources outside the source category is required under the statute. The statute requires the EPA to provide the quantitative risk information necessary to inform RTR regulatory decisions, and to this end, the EPA conducted a comprehensive assessment of the risks associated with exposure to the HAP emitted by the source category and supplemented that with additional

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[5] Integrated Risk Information System (IRIS). IRIS Guidance documents available at *http://www.epa.gov/iris/backgrd.html.*

[6] *http://yosemite.epa.gov/sab/sabproduct.nsf/0/b031ddf79cffded38525734f00649caf!OpenDocument&TableRow=2.3#2.*

information available about other possible concurrent and relevant risks.

Further, the risk assessment modeling accounts for the effects of multiple facilities that may be in close proximity when estimating concentration and risk impacts at each block centroid. When evaluating the risks associated with a particular source category, we combined the impacts of all facilities within the same source category and assessed chronic exposure and risk for all census blocks with at least one resident (*i.e.*, locations where people may reasonably be assumed to reside). The MIR considers the combined impacts of all sources in the category that may be in close proximity (*i.e.*, cumulative impact of all refineries).

Comment: Several commenters stated that the EPA underestimated exposure because emissions are underreported and underestimated. The commenters noted that for the risk assessment for the refineries rule, the EPA evaluated (1) the emissions reported to the agency pursuant to the 2011 Petroleum Refinery ICR as sources' ''actual'' emissions, and (2) the emissions the EPA estimates that the existing standards currently allow sources to emit using the REM, which it describes as ''allowable'' emissions. According to the commenters, both the EPA's ''actual'' and ''allowable'' emissions data sets are incomplete and undercount emissions, causing the EPA to significantly underestimate the resulting risk in its risk analysis. For example, the commenters noted that the EPA assumed the flare destruction efficiency to be 98 percent, while the EPA's own estimates suggest flare efficiency is 93.9 percent. The commenters also noted that the EPA has further understated risks by ignoring emissions during unplanned SSM events and by ignoring HAP for which no reference values are established. One commenter cited the TCEQ Emissions Event Database as evidence that SSM emissions are a severe public health problem because data show that nearly 1 million pounds of HAP are reported from Texas refineries between 2009 and 2013. According to these commenters, the EPA needs to adopt standards that provide greater protection, including protection from the risks of accidents.

Response: We used the best and most robust facility-specific HAP emissions inventory available to us, which was the 2011 ICR, in performing the analysis for the proposed rule. We conducted a thorough and exhaustive review of the data submitted through the ICR and we followed up on source-specific information on a facility-by-facility basis, as documented in the ''Emissions Data Quality Memorandum and Development of the Risk Model Input File'' (see Docket ID No. EPA–HQ–OAR–2010–0682–0076). In addition, we took steps ahead of issuing the 2011 ICR to make sure that facilities could, as accurately as practicable, estimate their HAP emissions for purposes of responding to the inventory portion of that ICR. We prepared a Refinery Protocol to provide guidance to refinery owners or operators to use the best available, site-specific data when developing their emissions inventory, to ensure all emission sources are included in the inventory, and to have a consistent set of emission factors that all respondents use if no site-specific emissions data were available. If site-specific emissions data were available, sites were to use these data preferentially over the default factors. We developed the default factors provided in the protocol from the best data available at the time.

The ICR-submitted information for allowable emissions did not include emission estimates for all HAP and all emission sources. Consequently, we used the REM to estimate allowable emissions. The REM relies on model plants that vary based on throughput capacity. Each model plant contains process-specific default emission factors, adjusted for compliance with the Refinery MACT 1 and 2 emission standards.

We agree with the commenters that studies have shown that many refinery flares are operating less efficiently than 98 percent. Prior to proposing this rule, we conducted a flare ad hoc peer review to advise the EPA on factors affecting flare performance (see discussion in the June 30, 2014, proposal at 79 FR 36905). However, we disagree with the commenters that the risk analysis should consider this level of performance since the existing MACT standard does not allow it. For purposes of the risk analysis, we evaluate whether it is necessary to tighten the existing MACT standard in order to provide an ample margin of safety. Thus, in reviewing whether the existing standards provide an ample margin of safety, we review the level of emissions the MACT standards allow. In the present case, we considered the level of performance assumed in establishing the MACT standard for purposes of determining whether the MACT standard provides an ample margin of safety. However, we did recognize that facilities were experiencing performance issues with flares and that many flares were not meeting the assumed performance level at the time we promulgated the MACT standard. Thus, we proposed, and are finalizing, revisions to the flare operating requirements to ensure that the flares meet the required performance level. These provisions are consistent with the EPA's goals to improve the effectiveness of our rules.

Similarly, we do not include startup, shutdown (including maintenance events) and malfunction emissions that are not allowed under the standard as part of our evaluation of whether the standards provide an ample margin of safety. Regarding the HAP emissions from SSM events that the commenter is concerned with, we note that our review of the TCEQ incident database indicates that many of the large reported release events were of SO_2 emissions and only a few had significant HAP emissions.

Because in the final rule we are establishing work practice standards for PRD and emergency flaring events, we performed a screening-level risk analysis to address changes in facility HAP emission releases due to these events. Details on this analysis are presented in the final risk report for the source category (For more details see Appendix 13 of the ''Final Residual Risk Assessment for the Petroleum Refining Source Sector,'' Docket ID No. EPA–HQ–OAR–2010–0682).

As for HAP with no reference value, the SAB addressed this issue in its May 7, 2010, response to the EPA Administrator. In that response, the SAB Panel recommended that, for HAP that do not have dose-response values from the EPA's list, the EPA should consider and use, as appropriate, additional sources for such values that have undergone adequate and rigorous scientific peer review. The SAB panel further recommended that the inclusion of additional sources of dose-response values into the EPA's list should be adequately documented in a transparent manner in any residual risk assessment case study. We agree with this approach and have considered other sources of dose-response data when conducting our risk determinations under RTR. However, in some instances no sources of information beyond the EPA's list are available. Compounds without health benchmarks are typically those without significant health effects compared to compounds with health benchmarks, and in such cases we assume these compounds will have a negligible contribution to the overall health risks from the source category. A tabular summary of HAPs that have dose response values for which an exposure assessment was conducted is presented in Table 3.1–1 of the ''Final Residual Risk Assessment for the Petroleum Refining Source Sector'', Docket ID No. EPA–HQ–OAR–2010–0682.

Comment: A few commenters asserted that the EPA should decide that it is unjust and inconsistent with the CAA's health protection purpose to allow the high health risks caused by refineries to fall disproportionately on communities of color and lower income communities who are least equipped to deal with the resulting health effects. Because of that disparity, the commenter stated that the EPA should recognize that the risks found are unacceptable and set stronger national standards for all exposed Americans.

Response: For this rulemaking, the EPA conducted both pre- and post-control risk-based assessments with analysis of various socio-economic factors for populations living near petroleum refineries (see Docket ID Nos. EPA–HQ–OAR–2010–0682–0226 and –0227) and determined that there are more African-Americans, Other and multiracial groups, Hispanics, low-income individuals, and individuals with less than a high school diploma compared to national averages. In determining the need for tighter residual risk standards, the EPA strives to limit to no higher than 100-in-1 million the estimated cancer risk for persons living near a plant if exposed to the maximum pollutant concentration for 70 years and to protect the greatest number of persons to an individual lifetime risk of no higher than 1-in-1 million. Although we consider the risk for all people regardless of racial or socioeconomic status, communities near petroleum refineries will particularly benefit from the risk reductions associated with this rule. In particular, as discussed later, the fenceline monitoring work practice standard will be a further improvement in the way fugitive emissions are managed and will provide an extra measure of protection for surrounding communities.

4. What is the rationale for our final decisions for the risk review?

As described in section IV.A.2 of this preamble, we performed a screening-level analysis to assess the risks associated with inventory updates we received for specific facilities and with emissions events that were previously not included in the risk assessment because the proposed rule did not allow them. Because we are finalizing work practice standards to regulate emission events associated with PRD releases and emergency flaring, we considered the effect these work practice standards would have on risks. As discussed in section IV.A.2 of this preamble, we project that accounting for these emergency events in the baseline risks after implementation of the MACT standards does not appreciably change the risks, and at most, could increase the proposed rule estimate of MIR by approximately 2-in-1 million. Therefore, we would project that any controls applied to these emergency events, including the work practice standards for PRDs and emergency flaring in this final rule, would not appreciably change the proposed post-control risks. Although we would anticipate minimal additional risk reductions, we reviewed more stringent alternatives to the work practice standards for PRD releases and emergency flaring events included in this final rule, and we found that the costs of increasing flare capacity to control all PRD releases and to eliminate all visible emissions during emergency flaring were too high. We estimate the capital costs of applying the velocity and visible emissions limit at all times would be approximately $3 billion, and we estimate that the costs of controlling all PRD releases with flares would be approximately $300 million. [See the discussion in the ''Flare Control Option Impacts for Final Refinery Sector Rule'', Docket ID No. EPA–HQ–OAR–2010–0682 and the PRD work practice standard discussion in section IV.C of this preamble.] Further, we did not receive comments on additional control technologies that we should have considered for other emission sources (*e.g.*, tanks, DCUs) beyond those considered and described at proposal. Consequently, as discussed in section IV.A.2, we conclude that the risks from the Petroleum Refinery source categories are acceptable and that, with the additional requirements for storage vessels that we are finalizing, as proposed, the Refinery MACT 1 and 2 rules provide an ample margin of safety to protect public health. We also maintain, based on the rationale presented in the preamble to the proposed rule, that the current standards prevent, taking into consideration costs, energy, safety and other relevant factors, an adverse environmental effect.

B. Technology Review for the Petroleum Refinery Source Categories

1. What did we propose pursuant to CAA section 112(d)(6) for the Refinery MACT 1 (40 CFR part 63, subpart CC) source category?

The results of our technology review for the Petroleum Refinery source categories were published in the June 30, 2014, proposal at (79 FR 36913 through 36928). The technology review was conducted for both MACT source categories as described below.

a. Refinery MACT 1

Refinery MACT 1 sources include MPV, storage vessels, equipment leaks, gasoline loading racks, marine vessel loading operations, cooling towers/heat exchange systems and wastewater. Based on technology reviews for the sources described above, we proposed that it was not necessary to revise Refinery MACT 1 requirements for MPV, gasoline loading racks, cooling towers/heat exchange systems, and wastewater. For storage vessels, we proposed revisions pursuant to the technology review. Specifically, we proposed to cross-reference the storage vessel requirements in the Generic MACT (40 CFR part 63, subpart WW) to require controls on floating roof fittings (*e.g.*, guidepoles, ladder wells and access hatches) and to revise the definition of Group 1 storage vessels to include smaller tanks with lower vapor pressures. For equipment leaks, we proposed to allow refineries to meet LDAR requirements in Refinery MACT 1 by monitoring for leaks via optical gas imaging in place of the EPA Method 21, using monitoring requirements to be specified in a not-yet-proposed appendix K to 40 CFR part 60. For marine vessel loading, we proposed to amend the Marine Tank Vessel Loading Operations MACT standards (40 CFR part 63, subpart Y) to require small marine vessel loading operations (*i.e.*, operations with HAP emissions less than 10/25 tpy) and offshore marine vessel loading operations at petroleum refineries to use submerged filling based on the cargo filling line requirements in 46 CFR 153.282.

We also proposed an additional work practice standard under the technology review to manage fugitive emissions from the entire petroleum refinery through a fenceline monitoring and corrective action standard. As part of the work practice standard, we specified the monitoring technology and approach that must be used, and we developed a fenceline benzene concentration action level above which refinery owners or operators would be required to implement corrective action to reduce their fenceline concentration to below this action level. The action level we proposed was consistent with the emissions projected from fugitive sources compliant with the provisions of the refinery MACT standards as modified by the additional controls proposed for storage vessels.

b. Refinery MACT 2

The Refinery MACT 2 source category regulates HAP emissions from FCCU, CRU and SRU process vents. We proposed to revise Refinery MACT 2 to incorporate the developments in monitoring practices and control technologies reflected in Refinery NSPS subpart Ja (73 FR 35838). This included proposing to incorporate the Refinery NSPS subpart Ja PM limit for new FCCU sources and to revise the monitoring provisions in Refinery MACT 2 to require all FCCU sources to meet operating limits consistent with the requirements in Refinery NSPS subpart Ja. The existing MACT standard provided that a refiner could demonstrate compliance with the PM limit in the MACT by meeting the 30-percent opacity limit requirement of Refinery NSPS subpart J; we proposed to eliminate that provision and instead establish control device operating limits or site-specific opacity limits similar to those required in Refinery NSPS subpart Ja. We also proposed to incorporate the use of 3-hour averages rather than daily averages for monitoring data to demonstrate compliance with the FCCU site-specific opacity and Ni operating limits. We proposed additional control device-specific monitoring alternatives for various control devices on FCCU, including BLD monitoring as an option to COMs for owners or operators of FCCU using fabric filter-type control systems, and total power and secondary current operating limits for owners or operators of ESPs. We also proposed to add a requirement to perform daily checks of the air or water pressure to atomizing spray nozzles for owners or operators of FCC wet gas scrubbers. Finally, we proposed to require a performance test once every 5 years for all FCCU in place of the one-time performance test required by the current Refinery MACT 2.

At proposal, we did not identify any developments in practices, processes and control technologies for CRU process vents based on our technology review. For SRU, we proposed to include the Refinery NSPS subpart Ja allowance for oxygen-enriched air as a development in practice and to allow SRU to comply with Refinery NSPS subpart Ja as a means of complying with Refinery MACT 2.

2. How did the technology review change for the Petroleum Refinery source categories?

a. Refinery MACT 1

We are finalizing most of our technology review decisions for Refinery MACT 1 emissions sources as proposed; however, as described briefly below, we are revising certain proposed requirements.

We are not taking final action adopting the use of appendix K to 40 CFR part 60 for optical gas imaging for refinery equipment subject to the LDAR requirements in Refinery MACT 1 because we have not yet proposed appendix K.

After considering the public comments, we are finalizing the proposed fenceline monitoring requirements, with a few revisions. First, we have made numerous clarifications in this final rule to the language for the fenceline monitoring siting method and analytical method (*i.e.*, Methods 325 A and B, respectively). Specific comments on these methods, along with our responses and explanations of the revisions to the regulatory text are discussed in the ''Response to Comment'' document. Second, we are finalizing a revised compliance schedule for fenceline monitoring, which will require refinery owners or operators to have the fenceline monitors in place and collecting benzene concentration data no later than 2 years from the effective date of the final rule, as opposed to 3 years in the proposed rule. Third, we have removed the requirement for refinery owners or operators to obtain the EPA approval for the corrective action plan. Fourth, we are requiring the submittal of the fenceline monitoring data on a quarterly basis, as opposed to on a semiannual basis as proposed. Fifth, we are providing guidelines for operators to use in requesting use of an alternative fenceline monitoring technology to the passive sorbent samplers set forth in Method 325B. Finally, to reduce the burden of monitoring, we are finalizing provisions that would allow refinery owners or operators to reduce the frequency of fenceline monitoring for areas that consistently stay well below the fenceline benzene concentration action level. Specifically, we are allowing refinery owners or operators to monitor every other two weeks (*i.e.*, skip period monitoring) if over a two-year period, each sample collected at a specific monitoring location is at or below 0.9 $\mu g/m^3$. If every sample collected from that sampling location during the subsequent 2-years is at or below 0.9 $\mu g/m^3$, the monitoring frequency may be reduced from every other two weeks to quarterly. After an additional two years, the monitoring can be reduced to semiannually and finally to annually, provided the samples continue to be at or below 0.9 $\mu g/m^3$ during all sampling events at that location. If at any time a sample for a monitoring location that is monitored at a reduced frequency returns a concentration greater than 0.9 $\mu g/m^3$, the owner or operator must return to the original sampling requirements for one quarter (monitor every two weeks for the next six monitoring periods for that location); if every sample collected from this quarter is at or below 0.9 ug/m^3, then the sampling frequency reverts back to the reduced monitoring frequency for that monitoring location; if not then the sampling frequency reverts back to the original biweekly monitoring frequency.

b. Refinery MACT 2

We are finalizing, as proposed, our determination that it is not necessary to revise the requirements for CRU pursuant to the technology review and we are finalizing our determination that it is necessary to revise the MACT for SRU and FCCU. For SRU, we are finalizing the revisions as proposed. For FCCU, we are making modifications to the proposed requirements in light of public comment.

As discussed previously, we proposed to remove the alternative in Refinery MACT 2 for owners or operators to demonstrate compliance with the PM limits on FCCU by meeting a 30-percent opacity standard as provided in Refinery NSPS subpart J and instead make the FCCU operating limits in Refinery MACT 2 consistent with Refinery NSPS subpart Ja. Based on the Refinery NSPS subpart J review in 2008, we determined that a 30-percent opacity limit does not adequately assure compliance with the PM emissions limit (see discussion in the proposed rule at 79 FR 36929, June 30, 2014). Thus, we included other monitoring approaches in Refinery NSPS subpart Ja.

Comments received on this proposal, along with data available to the Agency, confirmed that the 30-percent opacity standard is not adequate on its own to demonstrate compliance with the PM (or metal HAP) emissions limit in Refinery MACT 2. We also received comments that the site-specific opacity alternative, which is the only compliance option proposed for FCCU with tertiary cyclones, would essentially require owners or operators with these FCCU configurations to meet an opacity limit of 10-percent. According to commenters, opacity increases with decreasing particle size, so that it is common to exceed 10-percent opacity during soot blowing or other similar events that produce very fine particulates even though mass emissions have not changed appreciably.

Based on the available data, we have determined that a 20-percent opacity operating limit is well correlated with facilities meeting a limit of 1.0 lb PM/1,000 lbs coke burn-off. Therefore, we are retaining the option in Refinery MACT 2 to comply with Refinery NSPS subpart J except we are adding a 20-percent opacity operating limit in Refinery MACT 2, evaluated on a 3-hour basis. To ensure that FCCU owners or operators complying with the Refinery NSPS subpart J option can meet the 1.0 lb PM/1,000 lbs emissions limit at all times, we are finalizing requirements that owners or operators conduct the performance test during higher PM periods, such as soot blowing. Where the PM emissions are within 80-percent of the PM limit during any periodic performance test, we are requiring the refinery owner or operator to conduct subsequent performance tests on an annual basis instead of on a 5-year basis.

We are finalizing our proposed requirement that compliance with the control device operating limits in the other compliance alternatives be demonstrated on a 3-hour basis, instead of the 24-hour basis currently allowed in Refinery MACT 2.

3. What key comments did we receive on the technology review, and what are our responses?

a. Refinery MACT 1

The majority of comments received regarding the proposed amendments to Refinery MACT 1 pursuant to our technology review dealt with the proposed fenceline monitoring requirements. The primary comments on the fenceline monitoring requirements are in this section along with our responses. Comment summaries and the EPA's responses for additional issues raised regarding the proposed requirements resulting from our technology review are in the ''Response to Comment'' document in the public docket (Docket ID No. EPA–HQ–OAR–2010–0682).

i. Legal Authority and Need for Fenceline Monitoring

Comment: Numerous commenters claimed that the proposed fenceline monitoring program would unlawfully impose what is effectively an ambient air quality standard for benzene, which is not authorized by CAA section 112, which only authorizes the control of emission sources. The commenters argued it is an ambient standard because sources are required to meet the benzene level set or ''perform injunctive relief which may or may not address the source of the benzene.'' The commenter quoted language from the proposal as support that EPA has described the benzene level as an ambient standard: ''We are proposing a HAP concentration to be measured in the ambient air around a refinery, that if exceeded, would trigger corrective action to minimize fugitive emissions.'' 79 FR at 36920 (June 30, 2014). The commenter further noted that this requirement is not just ''monitoring'' because it establishes a ''not-to-be exceeded'' level. Therefore, the commenters stated, the EPA should not finalize this portion of the proposal.

Response: We disagree with the comment that the fenceline proposal is an ambient air standard. First, the owner or operator must place the monitors on the facility fenceline to measure emissions from the facility, *i.e.*, on the property of the refiner. While we recognize that we used the term ''ambient air'' in the preamble to the proposal, we note that the placement requirements for the monitors make clear that the monitors are not monitoring ambient air, which EPA has defined at 40 CFR 50.1(e) as ''that portion of the atmosphere, external to buildings, to which the general public has access.'' Second, the proposed EPA Method 325A sets out procedures to subtract background concentrations and contributions to the fenceline benzene concentrations from non-refinery emission sources, so that the benzene concentrations measured are attributable to the refinery. In other words, the fenceline monitoring work practice standard uses a benzene concentration difference, referred to as the ΔC (essentially an upwind and downwind concentration difference) to isolate the refinery's emissions contribution.

Furthermore, we disagree that the fact that refiners are required to perform corrective action if the fenceline benzene concentration action level is exceeded makes the benzene action level an ambient standard. As an initial matter sources are not directly responsible for demonstrating that an area is meeting an ambient standard; rather that burden falls on states. See *e.g.*, CAA section 110(a)(2). Moreover, the ''corrective action'' is simply that sources must ensure that fugitive emission sources on the property are not emitting HAP at levels that will result in exceedances of the fenceline benzene concentration action level. In other words, the purpose of the fenceline monitoring work practice is to ensure that sources are limiting HAP emissions at the fenceline, which are solely attributable to emissions from sources within the facility. In fact, the fenceline benzene concentration action level was established using emissions inventories reported by the facilities, assuming compliance with the MACT standards. Finally, monitoring is conducted as part of the work practice standard to identify sources that will require additional controls to reduce their impact on the fenceline benzene concentration. In that sense, the fenceline monitoring work practice standard is not different than, for example, our MACT standard for refinery heat exchangers. If a facility is exceeding the relevant cooling water pollutant concentration ''level'' when it performs a periodic test, it must undertake corrective action to bring the concentration down below the action level.

Comment: Several commenters noted that EPA's authority under section 112(d) is to set ''emissions standards'' and quoted the CAA definition of that term: ''A requirement . . . which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction, and any design, equipment, work practice or operational standard promulgated under this Act.'' 42 U.S.C. 7602(k). The commenters argued that the proposed fenceline monitoring standard does not meet this definition because it would not ''limit the quantity, rate, or concentration of emissions'' from any given emissions point. Also, the commenters claimed that the EPA did not designate fenceline monitoring as a work practice under CAA section 112(h) since the EPA did not even mention CAA section 112(h), nor did it conduct any analysis to show that fenceline monitoring meets the CAA section 112(h) factors.

Response: We disagree with the commenters' assertion that the proposed fenceline monitoring work practice standard is not authorized under CAA section 112(d)(6). Contrary to the commenter's claims, we specifically proposed the fenceline monitoring standard under CAA section 112(d)(6) to be a work practice standard that is applied broadly to fugitive emissions sources located at petroleum refineries. As discussed above, the proposed standard does more than impose monitoring as some commenters suggested; it also will limit emissions from refineries because it requires the owner or operator to identify and reduce HAP emissions through a monitoring and repair program, as do many work practice standards authorized under CAA Section 112(h) and 112(d).

We note that the sources addressed by the fenceline monitoring standard—refinery fugitive emissions sources such as wastewater collection and treatment operations, equipment leaks, heat exchange systems and storage vessels in the Refinery MACT 1 rule—are already subject to work practice standards. Our review of these requirements indicates that this fenceline monitoring work practice standard would be a further improvement in the way fugitive emissions are managed and would provide an extra measure of protection for surrounding communities. The commenter claims EPA did not analyze how the fenceline monitoring requirement meets the criteria in section 112(h). However, that is a misinterpretation of how the criteria apply. The criteria are assessed with regard to whether it is feasible to ''prescribe or enforce an emission standard for a source'', and do not apply to the work practice standard. Consistent with the criteria in section 112(h)(2), we determined and established that work practice standards are appropriate for these Refinery MACT fugitive emissions at the time we established the initial MACT standard. In the proposal, (79 FR at 36919, June 30, 2014), we reaffirmed that it is impracticable to directly measure fugitive emission sources at refineries but did not consider it necessary to reiterate these findings as part of this proposal to revise the existing MACT for these sources under CAA section 112(d)(6). We note that the commenters do not provide any grounds to support a reevaluation of whether these fugitive emission sources are appropriately regulated by a work practice standard.

Comment: Several commenters questioned the EPA's authority under the CAA to promulgate a rule that amounts to an ongoing information gathering and reporting obligation. The commenters stated that the EPA has not demonstrated that the proposed fenceline monitoring program represents an actual emission reduction technology improvement. A commenter stated that compliance assurance methods, including monitoring, for fugitive emissions and other emission standards are established as part of the emission standard and EPA's authority to gather information that is not directly required for compliance with a specific standard but is related to air emissions is found in CAA section 114. Under CAA section 114, the requirement must be related to one of the stated purposes and must be reasonable. The commenter did not believe that the EPA has demonstrated that the costs of fenceline monitoring are reasonable in light of the information already available to the EPA and in light of many other means by which the EPA could obtain such information.

Response: We disagree with the commenters' assertion that the authority for the fenceline monitoring requirement falls under CAA section 114 and not CAA section 112(d) because it is an ''ongoing information gathering and reporting obligation.'' The issue here is not whether EPA could have required the fenceline monitoring requirement under CAA section 114, but rather did EPA support that it was a development in processes practices or controls technology under section 112(d)(6).

As an initial matter, we disagree with the commenters' characterization of the fenceline monitoring standard as ''an information gathering and reporting obligation.'' We have repeatedly stated that we consider the fenceline monitoring requirement to be a work practice standard that will ensure sources take corrective action if monitored benzene levels (as a surrogate for HAP emissions from fugitive emissions sources) exceed the fenceline benzene concentration action level. The standard requires refinery owners or operators to monitor the benzene concentration at the refinery perimeter, to evaluate the refinery's contribution as estimated by taking the concentration difference between the highest and lowest concentrations (ΔC) in each period, and to conduct root cause analysis and take corrective action to minimize emissions if the concentration difference is higher (on an annual average) than the benzene concentration action level. Thus, the fenceline monitoring requirement goes well beyond ''information gathering and reporting.''

In addition, the commenters again read section 112(d)(6) too narrowly by suggesting that a program considered as a development must be a ''technology'' improvement. Section 112(d)(6) of the CAA requires the EPA to review and revise the MACT standards, as necessary, taking into account developments in ''practices, processes and control technologies.'' Consistent with our long-standing practice for the technology review of MACT standards, in section III.C of the proposal (see 79 FR 36900, June 30, 2014), we list five types of ''developments'' we consider. Fenceline monitoring fits squarely within two of those five types of developments (emphasis added):

- Any add-on control technology or other equipment that was not identified and considered during development of the original MACT standards.
- Any work practice or operational procedure that was not identified or considered during development of the original MACT standards.

As used here, ''other equipment'' is clearly separate from and in addition to ''add-on control'' technology and is broad enough to include monitoring equipment. In this case, fenceline monitoring is a type of equipment that we did not identify and consider during development of the original MACT standards. Additionally, the fenceline standard is a work practice standard, involving monitoring, root cause analysis and corrective action not identified at the time of the original MACT standards. Therefore, the fenceline requirements are a development in practices that will improve how facilities manage fugitive emissions and EPA appropriately relied on section 112(d)(6) in requiring this standard.

Comment: Some commenters contended that because the fenceline monitoring standard is in essence an ambient standard, the only justification that can be used to support it would be under CAA section 112(f)(2). The commenters stated that EPA determined that the MACT standards pose an acceptable level of risk and protect the public health with an ample margin of safety and thus, section 112(f) does not support imposition of the fenceline monitoring requirement. Several commenters stated that the Agency expressly acknowledges that imposition of additional emission standards for fugitive emissions from refinery sources are not warranted under CAA section 112(f). Some commenters suggested that because the existing MACT standards protect public health with an ample margin of safety, the fenceline monitoring requirement imposes an unnecessary burden on industry because it is not necessary to achieve acceptable risk or provide an ample margin of safety.

Response: EPA is not relying on section 112(f)(2) as the basis for the fenceline monitoring requirement. As provided in a previous response to comment, we disagree with the commenters that the fenceline monitoring requirement is an ambient standard and therefore, we do not need to consider what authority would be appropriate for establishing an ambient standard that would apply to fugitive sources of emissions at refineries. We also disagree with the commenters who suggest that EPA may not require fenceline monitoring pursuant to section 112(d)(6) because EPA has not determined that fenceline monitoring is necessary to ensure an acceptable level of risk or the provide an ample margin of safety. Section 112(d)(6) does not require EPA to factor in the health considerations provided in section 112(f)(2) when making a determination whether it is ''necessary'' to revise the MACT.

Comment: Commenters stated that the pilot studies undertaken by the EPA and pilot studies undertaken by the refining industry (see the API Fenceline Study in the docket for this rulemaking) demonstrate either that there is no underestimation of emissions and thus, no need for the fenceline monitoring work practice standard, or that fenceline benzene data cannot be used to validate emission estimates. Commenters stated that none of the refineries in the API study of the proposed refinery fenceline standard had study-averaged ΔC concentrations that exceeded the proposed action level of 9 μg/m³ and thus the study provides some evidence that U.S. refineries are not underestimating emissions. Furthermore, the commenter stated that there is significant ambient air monitoring performed that further supports low benzene concentrations in the vicinities of refineries and cited ambient monitoring data collected by the Southeast Texas Regional Planning Commission Air Quality Group and the Texas Commission on Environmental Quality (TCEQ).

Response: We disagree that the API fenceline study demonstrates that there is no underestimation of emissions. The API report referred to by the commenter actually shows higher ΔC concentrations than what we expected, when we compare the distribution of ΔC's presented in the API fenceline study to the distribution of benzene concentrations at the 142 refineries we modeled (see memorandum ''Fenceline Ambient Benzene Concentrations Surrounding Petroleum Refineries'', EPA–HQ–OAR–2010–0682–0208). [Note that API did not identify the facilities in their study, so we were not able to perform a one-to-one comparison of the measured ΔC concentrations with the modeled fenceline concentrations.] Furthermore, the API conducted the study primarily during the fall and winter months (October to March) when the ambient temperatures are lower than the annual averages. While this may not impact equipment leak emissions, temperature can have a significant impact on emissions from storage vessels and wastewater treatment systems, so it is likely that the annual average ΔC for the facilities tested could be higher than the ''winter'' averages measured in the API study. Based on our review of the API study data, we interpret the results to indicate that there may be higher concentrations of benzene on the fenceline attributable to fugitive emissions than anticipated at some facilities. These studies are an indication that the standard we are finalizing will achieve the goal of ensuring that the owners or operators manage fugitive emissions within the refinery.

This regulatory approach also fits with the EPA's goals to improve the effectiveness of rules. Specifically, in this case, we are improving the effectiveness of the rule in two ways. First, we are establishing a fenceline benzene trigger to manage overall fugitive HAP emissions, rather than establishing further requirements on many individual emission points. Secondly, the rule incentivizes facilities to reduce fugitive HAP emissions below the fenceline benzene trigger by providing regulatory options for reduced monitoring.

Regarding ambient monitoring data, we note that existing ambient monitors are not located at the fenceline; they are located away from sources, and concentrations typically decrease exponentially with distance from the emissions source. We are encouraged that data referenced by the commenter indicate that ambient levels of benzene are within levels that are protective of human health in communities, but note that analysis of benzene concentrations in communities does not necessarily indicate that refineries located near these communities are adequately managing their fugitive HAP emissions.

Comment: Several commenters reiterated that they do not believe the proposed fenceline monitoring is a technology development for equipment leaks, storage vessels or wastewater sources. However, if the EPA finalizes the fenceline monitoring requirements, the commenters suggested that there is no longer a need or regulatory basis for imposing both the fenceline monitoring requirements and the existing MACT standards for fugitive HAP emission sources. Thus, the EPA should remove the current MACT requirements for LDAR, storage vessels and wastewater handling and treatment from Refinery MACT 1 if the EPA promulgates fenceline monitoring. Addition of fenceline monitoring on top of the existing MACT requirements, they argue, would violate the Executive Order 12866 mandate to avoid redundant, costly regulatory requirements that provide no emission reductions.

Response: We disagree that the fenceline monitoring standards we are finalizing in this rule are redundant to MACT emissions standards for fugitive HAP emissions sources. The MACT standards impose requirements on fugitive HAP emissions sources consistent with the requirements in CAA section 112(d)(2) & (3), and the fenceline monitoring requirement is not a replacement for those requirements. Rather, based on our review of these standards, we concluded that fenceline monitoring is a development in practices, processes or control technologies that would improve management of fugitive emissions in a cost-effective manner. In selecting this development as an across-the-board means of improving management of fugitive emissions, we rejected other more costly developments that would have applied independently to each fugitive emissions source. Requiring refineries to establish a fenceline monitoring program that identifies HAP emission sources that cause elevated benzene concentrations at the fenceline and correcting high emissions through a more focused effort augments but does not replace the existing requirements. We found that, through early identification of significant fugitive HAP releases through fenceline monitoring, compliance with the existing MACT standards for these emissions sources could be improved and that it was necessary to revise the existing standards because fenceline monitoring is a cost-effective development in processes, practices, and control technologies.

We note that the existing MACT requirements are based on the MACT floor (the best performers), and as such, provide a significant degree of emission reductions from the baseline. The action level for the fenceline work practice standard, by contrast, is not based on the best performers but rather on the highest value expected on the fenceline from any refinery, based on the modeling of refinery emission inventories. As such it is not representative of the best performers and could not be justified as meeting the requirements of section 112(d)(2)and (3). If we were to remove the existing standards for fugitive emission sources at the refinery, we would not be able to justify that sources are meeting the level of control we identified as the MACT floor when we first promulgated the MACT. Nor could we justify the fenceline monitoring program we are promulgating as representing the MACT floor because we considered cost (and not the best performers as previously noted) in identifying the components of the program. Although the fenceline monitoring standard on its own cannot be justified as meeting the MACT floor requirement for each of the separate types of fugitive emission sources, that does not mean that it is not an effective enhancement of those MACT requirements. To the contrary, it works in tandem with the existing MACT requirements to provide improved management of fugitive emissions and, in that sense, it is precisely the type of program that we believe Congress had in mind when enacting section 112(d)(6).

ii. Rule Should Require Real-Time Monitoring Technology for Fenceline Monitoring.

Comment: Numerous commenters stated that the proposed fenceline standards, which require monitoring using 2-week integrated passive samplers, are flawed and weak for a number of reasons, including that the monitoring method does not provide real-time data, does not provide adequate spatial coverage of the fenceline, and does not provide a mechanism to identify the specific emission source impacting the fenceline to manage fugitive emissions. Several commenters suggested that this monitoring technology is not state of the art. They claimed that there are superior systems in place at refineries that are technically and economically feasible, including at Shell Deer Park, Texas; BP Whiting, Indiana; and Chevron Richmond, California. Further, they claimed that these systems more effectively achieve the objective of reducing fugitive emissions. They claimed several systems are superior to the proposed system, including open-path systems such as ultraviolet differential optical absorption (UV DOAS) and Fourier transform infrared spectroscopy (FTIR), as well as point monitors such as gas chromatographs. A number of commenters suggested that open-path monitors should be required, stating that this technology is capable of providing real-time analysis and data on air pollution, is able to analyze multiple pollutants simultaneously at low, near-ambient concentrations, and is capable of providing more complete geographic coverage.

The commenters also stated that the benefits of real-time monitors are particularly important in communities close to refineries, where they believe refinery emissions are a major source of toxic pollutants and short-term upset events that can have significant public health impacts. In particular, the commenters stated that open-path monitors promote an individual's right-to-know, in real-time, about harmful pollution events affecting their communities, and will allow refinery owners or operators to immediately identify fugitive emissions and undertake swift corrective action to reduce these emissions. Some commenters suggested that, if the EPA rejects these open-path real-time monitors, then at a minimum the EPA should require the use of active daily monitoring, such as auto-gas chromatograph (GC) systems.

Finally, a number of commenters recommended that the EPA provide sufficient flexibility in its regulations to allow state and local jurisdictions to develop, demonstrate, and subsequently require the use of alternative monitoring programs, provided these monitoring programs are at least equivalent to those in the final rule.

Response: We understand that many commenters believe real-time monitoring would not only help refinery owners or operators in identifying emission sources, but also would warn the community of releases in real time.

Both open-path systems and active sampling systems (such as auto-GCs) mentioned by the commenters, are monitoring systems capable of yielding monitoring data quickly—ranging from a few minutes to about a day. However, these ''real-time'' systems have not been demonstrated to be able to achieve all of the goals stated by the commenters—specifically, able to provide real-time analysis and data on multiple pollutants simultaneously at low-, near-ambient concentrations, with more complete geographic (or spatial) coverage of the fenceline.

The real-time open-path systems suggested by the commenters are all limited in that they are not sensitive enough to detect benzene at the levels needed to ensure that fenceline monitoring achieves its intended goal. The fenceline monitoring system needs to be capable of measuring at sub-ppbv levels—well below the 9 $\mu g/m^3$ fenceline benzene concentration action level in the final rule, in order to determine the ΔC. In the proposal, we discussed two open-path monitoring technologies, FTIR and UV–DOAS. For the proposed rule, we analyzed the feasibility of employing UV–DOAS over FTIR because the UV–DOAS is more sensitive to detection of benzene than FTIR, as we described in the proposal. We reviewed performance data on several UV–DOAS systems in support of the proposed rule, and for this final rule, we considered information submitted during the comment period. We found that the lowest detection limit reported for any commercially-available UV–DOAS system is on the order of 3 ppbv over a 200-meter path length, whereas the fenceline benzene concentration action level is 2.8 ppbv (equivalent concentration to 9 $\mu g/m^3$). This system is being installed at the Shell Deer Park refinery but has not been field validated yet. Thus, we do not yet know the detection capabilities of the system, as installed. Based on the lowest reported detection limit, it cannot achieve the detection levels needed to demonstrate compliance with the fenceline standard in this final rule. This system also will only cover approximately 5 percent of the fenceline at Shell Deer Park, instead of the full fenceline coverage of the passive diffusive tube monitoring system we proposed. Facilities would have to deploy a monitoring system consisting of many open-path monitors to achieve the same spatial coverage as the passive diffusive tube monitoring system.

For the final rule, we also reviewed other UV–DOAS systems in operation at refineries that commenters identified. However, reported detection limits for these systems are even higher than for the type of system being installed at Shell Deer Park. For example, we reviewed the open-path UV–DOAS system information from BP Whiting and found that they were able to verify a detection limit of 8 ppbv path average concentration for benzene over a 1,500-meter optical path. This is well above the 2.8 ppbv fenceline benzene concentration action level, let alone the sub-ppbv levels necessary to determine the ΔC. Moreover, this system, though commercially available, was optimized by developing alternative software to improve the detection limit (see memorandum ''Meeting Minutes for April 21, 2015, Meeting Between the U.S. EPA and BP Whiting'' in Docket ID No. EPA–HQ–OAR–2010–0682). Thus, the system, as installed, would not be readily available to other refineries. We reviewed data for the UV–DOAS system at the Chevron Richmond refinery and found that this system, with optical path lengths ranging from 500 to 1,000 meters, has a reported benzene detection limit of 5 ppbv averaged over the path length. Again, this is above the fenceline benzene concentration action level at the fenceline established in this final rule. In addition, we could not find any information to support the reported detection limit. We note that the public Web site operated by the City of Richmond, California indicates that information provided by the system is informational only, not quality assured, and not to be used for emergency response or health purposes.

We also disagree with the commenter's claim that if the EPA does not finalize requirements for real-time open-path monitors then, at a minimum, the EPA should require active daily monitoring. There are two methods of active monitoring. One method, which we will refer to as the ''auto-GC method,'' uses a dedicated gas chromatograph at each monitoring location and can return ambient air concentration results multiple times a day or even hourly. The other method, which we refer to as ''method 2,'' uses an active pump to collect gas in a sorbent tube or in an evacuated canister over a 1-day period, for later analysis at a central location. While active sampling monitoring networks are capable of measuring multiple pollutants and would likely be able to detect benzene at sub-ppbv levels as necessary to demonstrate compliance with the fenceline requirements in this final rule, they consist of discreet monitors and would not provide any better spatial coverage of the refinery fenceline than a passive diffusive tube monitoring network. Further, as shown in Table 9 of the proposed rule (see 79 FR 36923, June 30, 2014), like open-path systems, an active sampling monitoring network would cost many times that of a passive diffusive tube monitoring network. At proposal, we estimated the costs of active daily sampling based on ''method 2'' to be approximately 10 times higher than for the proposed passive monitoring (see memorandum ''Fenceline Monitoring Technical Support Document'', Docket ID No. EPA–HQ–OAR–2010–0682–0210). We note that this type of active daily sampling based on method 2 does not necessarily yield results within 24 hours as the sample analysis would be conducted separately. We did not specifically estimate the costs of an auto-GC alternative, but the capital costs would be at least 20 to 30 times that for the passive diffusive tube system, would require shelters and power supplies at all monitoring locations and would have operating costs similar to the ''method 2'' active monitoring option we considered.

To date, there are no commercially-available, real-time open-path monitors capable of detecting benzene at the sub-ppbv levels necessary to demonstrate compliance with the fenceline requirements in this final rule. Only a system that can detect such levels will result in effective action by facilities to identify and control fugitive emissions in excess of those contemplated by the MACT standards. Further, active monitoring systems, while potentially capable of detecting benzene at sub-ppbv levels, like open-path systems, become very costly when enough monitors are located around the facility to approach the spatial coverage of the passive diffusive tubes. However, we believe that the state of technology is advancing and that the capabilities of these systems will continue to improve and that the costs will likely decrease. If a refinery owner or operator can demonstrate that a particular technology would be able to comply with the fenceline standards, the owner or operator can request the use of an alternative test method under the provisions of 40 CFR 63.7(f). A discussion of the specific requirements for these requests can be found in the first comment and response summary of Chapter 8.3 of the ''Response to Comment'' document.

Comment: One commenter stated that the required monitoring should include real-time monitoring of all chemicals released by refineries that pose risks to human health. The commenter stated that the limited scope of monitoring required by the proposed rule appears to be guided by the EPA's judgment that fugitive, or ''unintended'' emissions pose the greatest threat to public health. On the contrary, communities may well suffer from the effects of chemicals released into the air under normal, permitted emissions. A more expansive monitoring strategy would account for both routine and fugitive emissions.

Several commenters noted that monitoring is limited to benzene as opposed to multiple HAP. One commenter noted that ill health experienced by refinery neighbors is due in large part to the synergistic effects of multiple chemicals. Therefore, the commenter stated that it is essential that the rule require monitoring of the full range of chemicals with health implications. Other commenters recommended that the fenceline monitoring requirement be amended to include additional contaminants, such as VOC, that may negatively impact human health and the environment. Conversely, other commenters stated that the EPA has appropriately selected benzene as a target analyte and surrogate for HAP emissions from petroleum refineries, as benzene is a common constituent in refinery feedstocks and numerous refinery streams, and is present in most HAP-containing streams in a refinery.

Response: As part of the CAA section 112(d)(6) technology review, the EPA identified the fenceline monitoring standard as a development in practices, processes or control technologies that could improve management of fugitive HAP emissions. Thus, to the extent the commenter is suggesting that the EPA require the fenceline monitoring system to monitor for emissions of non-HAP pollutants, such request goes beyond the scope of our action. Furthermore, to the extent that the commenter is raising health concerns, although we address residual risk remaining after implementation of the MACT standards under CAA section 112(f)(2), we note that the MACT standards themselves, including this requirement, are aimed at protecting public health, especially in surrounding communities. As we explained in the proposal, and as we determine for this final rule, the MACT standards as modified by additional requirements for storage vessels, provide an ample margin of safety to protect public health. We did not propose and are not finalizing a fenceline monitoring requirement as necessary to provide an ample margin of safety under CAA section 112(f)(2).

Petroleum refining emissions can contain hundreds of different compounds, including many different HAP, and no single method can detect every HAP potentially emitted from refineries. While several HAP are amenable to quantification via passive diffusive tube monitoring using the same adsorbent tubes used for benzene (*e.g.,* toluene, xylenes and ethyl benzene, which have uptake rates in Table 12.1 in Method 325B), we selected benzene as a surrogate because it is present in nearly all refinery fugitive emissions. By selecting a single HAP as a surrogate for all fugitive HAP, we are able to establish a clear action level, which simplifies the determination of compliance for refinery owners or operators and simplifies the ability of regulators and the public to determine whether sources are complying with the work practice standard. As described in the proposal preamble, benzene is ubiquitous at refineries and present in nearly all refinery process streams, including crude oil, gasoline and wastewater. Additionally, benzene is primarily emitted from ground level, fugitive sources that are the focus of the work practice standard. Thus, we conclude that monitoring of benzene is appropriate and sufficient to identify emission events for which the monitoring program is targeting. Consequently, we are not requiring quantification of other pollutants although refinery owners or operators could choose to analyze the diffusive tube samples for additional HAP in conducting root cause analysis and corrective action.

iii. Fenceline Monitoring Action Level

Comment: Several commenters stated that the action level for fenceline monitoring (*i.e.,* 9 μg/m³ or 2.8 ppbv), was set too high. Some of these commenters noted that the EPA selected 9 μg/m³ as the highest modeled benzene concentration at any refinery fenceline. One commenter stated that this was arbitrary and capricious and stated the action threshold level makes little sense because only 2 of the 142 modeled facilities are expected to have fenceline concentrations above 4 μg/m³. Several commenters noted that the average modeled benzene concentration is 0.8 μg/m³, which is more than an order of magnitude less than the proposed fenceline benzene concentration action level.

Two commenters argued for a lower action level threshold, citing the proposed California OEHHA rule, which finalized new and revised benzene reference exposure levels (REL) that are more stringent than the ones the EPA used in the residual risk assessment supporting the proposed rule.

Two commenters stated that while the fenceline benzene concentration action level of 9 μg/m³ is relatively protective compared to standards adopted by many states, including Louisiana and Texas, it is still 80-percent higher than the European Union's standard of 5 μg/m³. The commenter urged the agency to consider adopting a stricter standard comparable to what other industrialized nations use.

Several commenters stated that the EPA's 9 μg/m³ action level is inconsistent with the statutory text and objectives of CAA sections 112(d) and (f), which direct the EPA to focus on the best-performing, lowest-emitting sources, in order to require the ''maximum achievable'' emission reductions. The commenters stated that the EPA promulgated the 9 μg/m³ limit without properly following the statutory requirements for establishing MACT floor limits, pointing out that the EPA made no determination of whether or not these general models were representative of the emissions levels actually achieved by the submitting refinery, and no connection was drawn between the best performing sources and the eventual 9 μg/m³ limit.

On the other hand, several commenters opposed the 9 μg/m³ action level suggesting that it was not achievable and that it is arbitrary. Some commenters noted that emission/dispersion models are always very site-specific and do not necessarily yield a result that is reliable or reproducible. Several commenters stated that additional studies are necessary to allow the agency to account for these variables and set a more appropriate concentration corrective action level. Commenters suggested a 2-year data gathering effort at all refineries and data evaluation before determining a specific threshold to use.

Several commenters recommended action levels ranging from 15 μg/m³ to 20 μg/m³ of benzene to account for the variability expected in monitoring data. The commenters stated that modeling biases have underestimated the necessary action level to achieve the stated goals of the program.

Response: First, it is important to note that the purpose of the standard has not changed between proposal and promulgation, namely that it is a technology-based standard that is an advancement in practices to manage fugitive emissions. It is not intended to be a separate or new MACT standard promulgated pursuant to CAA sections 112(d)(2) and (3) for which a ''floor'' analysis would be required.[7] Nor is it a standard that we are promulgating pursuant to CAA section 112(f)(2) as necessary to provide an ample margin of safety to protect public health or prevent an adverse environmental effect.[8] Thus, claims that a standard should reflect European Union health-based standards or the California OEHHA rule are misplaced. We also disagree with the suggestion that the proposed monitoring requirement will allow for higher emissions. As noted elsewhere, we are retaining all of the source-specific requirements for fugitive emissions sources that exist in Refinery MACT 1.

We disagree with the commenters that suggest that the proposed action level of 9 μg/m³ is too low and may not be achievable even for well-performing facilities. As discussed in the preamble for the proposed rule, we selected the 9 μg/m³ benzene action level because it is the highest value on the fenceline predicted by the dispersion modeling and, thus, is a level that we estimate that no refinery should exceed when in full compliance with the MACT standards, as amended by this final rule. All of the results of our pilot study, the API study, and the other ambient monitoring data near refineries clearly indicate that this level is achievable. Furthermore, we expect the fenceline concentration difference measured following the procedures in the final rule to be indicative of refinery source contributions and we have provided procedures to isolate these concentrations from outside sources, as well as background.

We expect that the fenceline monitoring standard will result in improved fugitive HAP emissions management as it will alert the refinery owners or operators of fugitive sources releasing high levels of HAPs, such as large leaks, faulty tank seals, etc.

iv. Fenceline Monitoring Root Cause Analysis and Corrective Action Provisions

Comment: A number of commenters objected to the proposal's ''open-ended'' provisions allowing the EPA to direct refinery owners or operators to change their operations in order to achieve the fenceline limit, with no regulatory limits on costs and without consideration of the impact to safe operations or operability of the plant. Another commenter stated that the EPA must properly assess the costs associated with the root cause analysis/corrective action requirements and should establish a cost effectiveness threshold for any required root cause analysis/corrective action to ensure that limited resources are effectively and efficiently applied for the control of emissions.

One commenter stated the proposed fenceline benzene concentration action level is effectively an ambient air standard, because corrective action to achieve that level is required and that if a facility's initial corrective action is unsuccessful, the rule provides that further action is required and the EPA must approve that further corrective action plan. Thus, the commenter argued, the EPA would essentially be able to dictate corrective actions, with no bounds on what could be required and no consideration of whether any cost-effective actions are available to assure the action level is met. The commenter continued that such a requirement converts a work practice program to an emission limitation and such ambient air limits are not authorized by CAA section 112. Several commenters noted that LDAR and current work practice programs have no similar requirement for the EPA approval, and the commenters suggested that the requirement for the EPA approval of any second corrective action should not be included in 40 CFR 63.658(h).

Another commenter recommended that, if after corrective action, a facility still has an exceedance for the next sampling episode, *then* the facility should be required to do more than it

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[7] To the extent that the commenters are suggesting that EPA must re-perform the MACT floor analysis for purposes of setting a standard pursuant to section 112(d)(6), we note that the D.C. Circuit has rejected this argument numerous times, most recently in National Association for *Surface Finishing et al.* v. *EPA No. 12–1459* in the U.S. Court of Appeals for the District of Columbia.

[8] Although we did not establish this limit to address residual risk under CAA section 112(f)(2), the limit was derived from the same inventory used for our risk modelling. Thus, based on our current reference concentration for benzene, the 9 μg/m³ action level will also ensure that people living near the refinery will not be exposed to cancer risks exceeding 100-in-1 million.

did after the first root cause analysis, as the prior corrective action clearly did not correct the problem. The commenter stated that one corrective action measure the EPA should include in all such instances is higher-quality monitoring such as UV–DOAS for at least 1 year to monitor, identify, correct and assure ongoing compliance after the exceedance problem is fixed.

Response: The ''on-going'' requirement to achieve the fenceline benzene concentration action level is no different in concept from the LDAR requirements for equipment or heat exchange systems in the Refinery MACT 1 rule, which requires the refinery owner or operator to repair the source of the emissions regardless of what it takes until compliance with the standard is achieved.

We disagree with the claim that the EPA must assess the costs associated with the root cause analysis/corrective action requirements and establish a cost effectiveness threshold for any required root cause analysis/corrective action to ensure that limited resources are effectively and efficiently applied for the control of emissions. We did not attempt to project the costs of the root cause analysis/corrective action for at least two reasons. First, based on the dispersion modeling of the benzene emissions reported in response to the inventory section of the 2011 ICR, we project that no refinery should exceed that fenceline benzene concentration action level if in full compliance with the MACT standards, as amended by this action. Thus, assuming compliance with the MACT standards, we would expect that there are no costs for root cause analysis/corrective action. To the extent that there are exceedances of the action level, the premise of the fenceline monitoring is to provide the refinery owners or operators with the flexibility to identify the most efficient approaches to reduce the emissions that are impacting the fenceline level. Since the choice of control is a very site-specific decision, we would have no way to know how to estimate the costs. Thus, the source is in the best position to ensure that resources are effectively and efficiently spent to address any exceedance.

We intended the proposed requirement for refinery owners or operators to submit a corrective action plan for the EPA approval to provide the Administrator with information that they were making a good-faith effort to reduce emissions below the fenceline benzene concentration action level, as expeditiously as practicable. However, we understand the importance for refinery owners or operators to begin corrective action as soon as possible, without having to wait for the EPA approval. Therefore, we are finalizing the requirement for refinery owners or operators to submit such plans but we are not finalizing the requirement that the EPA must approve the plan prior to the corrective action being taken.

We previously responded to comments regarding UV–DOAS or other open-path monitoring systems in this section, explaining that the current detection limits for these systems exceeds the action level threshold and, thus, these systems would not provide usable data to inform corrective action. Thus, we disagree that the EPA should require these systems for all facilities whose first attempt at corrective action is ineffective.

v. Fenceline Monitor Siting Requirements

Comment: Numerous commenters provided suggestions on, or requested clarification of, the monitor siting requirements. Several commenters stated that proposed Method 325A uses the terms ''fenceline or property boundary,'' while it should consistently use the term ''property boundary'' or even ''property line'' as the fenceline location. Several commenters stated that Sections 8.2.2.1.4 and 8.2.2.3 of Draft Method 325A specify that samplers be placed just beyond the intersection where the measured angle intersects the property boundary and this could require placing monitors on other people's property, in a road, in a water body or in a railroad right-of-way. The commenters suggested that facilities should be allowed to place monitors at any vector location that meets other requirements between the property boundary and the source nearest the property boundary. They stated that facilities need this clarification to avoid obstructions (*e.g.,* buildings or trees) that may be at the property line.

Numerous commenters requested that the rule clarify where monitors need to be placed in special circumstance, such as refineries bisected by a road, railroad or other public right-of-way or a boundary next to a navigable waterway. Several commenters stated that refiners should not need to place monitors on these property boundaries or other property boundaries where there are no residences within 500 feet of the property line. Commenters also asked if areas that had non-refinery operations, but are still inside the property boundary, would be included for purposes of determining where to site monitors.

A few commenters expressed concern about the approach for determining the number of required monitors at a site based on the acreage, noting that it is unfair to small facilities and will leave gaps in monitoring coverage for very large facilities. Some commenters recommended amending the proposed rule to require the placement of fenceline monitors at fixed distances along facilities' perimeters with no maximum number of monitors. Some commenters stated that the rule should specify an acceptable range on the 2,000-foot spacing requirement or the radial placement requirement as it may be necessary to address accessibility or safety concerns. Several commenters suggested that a lower minimum number of sampling monitors should be required for very small refineries or small ''subareas.'' These commenters noted that refineries often include disconnected parcels that can be very small (*e.g.,* 10 acres or less). If each disconnected parcel must be treated as a separate subarea, then both sampler siting options in Draft Method 325A would result in unnecessarily large numbers of samplers extremely close together. Some commenters recommended that Method 325A specify that samplers need not be placed closer than 500 feet (versus the normal 2,000-foot interval specified in Option 2) along the fenceline from an adjoining sampler, regardless of whether the radial or linear approach is used and should waive the minimum number of samplers specified in Sections 8.2.2.1.1, 8.2.2.2.1, and 8.2.3.1. Another commenter added that the rule should waive the requirement for additional samplers in Sections 8.2.2.1.5 and 8.2.3.5 if the 500-foot minimum spacing criterion is compromised.

Response: We agree that the Method 325A should provide clear and consistent language. We have revised the language to be consistent in referring to the ''property boundary''. We have also revised the Method to allow placement of monitors at any radial distance along either a vector location or linear location (that meets the other placement requirements) between the property boundary and the source nearest the property boundary. That is, the monitors do not need to be placed exactly on the property boundary or outside of the property boundary. They may be placed within the property closer to the center of the plant as long as the monitor is still external to all potential emission sources. We do note that if the monitors are placed farther in from the property boundary, the owner or operator should take care to ensure, if possible, that the radial distance from the sources to the monitors is at least 50 meters. If the perimeter line of the actual placement of the fenceline monitors is closer than 50 meters to one or more sources, then the additional monitor citing requirements will apply. We have revised subparagraphs of Section 8.2.2 to provide this allowance. This clarification should address issues related to obstructions such as tall walls located at the facility boundary.

We intended that the fenceline monitoring would create a monitoring perimeter capable of detecting emissions from all fugitive emission sources at the refinery facility. We have long established that a road or other right of way that bisects a plant site does not make the plant site two separate facilities, and, thus, would not be considered part of the property boundary. As we agree that monitors need only be placed around the property boundary of the facility, it would not be necessary to place monitors along a road or other right-of-way that bisects a facility. We have clarified this in the final rule and Method 325A.

If the facility is bounded by a waterway on one or more sides, then the shoreline is the facility boundary and monitors should be placed along this boundary. If the waterway bisects the facility, the waterway would be considered internal to the facility and monitors would only be needed at the facility perimeter.

Regarding the comment that monitors should not be required where there is no residence within 500 feet of the property line, we disagree. We proposed and are finalizing the fenceline monitoring standards under CAA section 112(d)(6) as a means to improve fugitive HAP emissions management, regardless of whether there are people living near a given boundary of the facility.

Regarding the clarification requested about monitor placement considering non-refinery operations, the property boundary monitors should be placed outside of all sources at the refinery. This is because moving the monitoring line inward to exclude the non-refinery source could lead to an underestimation of the ΔC compared to the monitoring external of the entire site. If the non-refinery source is suspected of contributing significantly to the maximum concentration measured at the fenceline, a site-specific monitoring plan and monitoring location specific near-field interfering source (NFS) corrections will be needed to address this situation.

Section 8.2.3 of Method 325A includes language to provide some flexibility when using the linear placement (±10% or ±250 feet). We consider it reasonable to provide similar placement allowance criteria for the radial placement option (±1 degree). We are not providing requirements that would allow small area refineries to use fewer than 12 monitoring sites. We do not consider that any refinery would be so small as to warrant fewer than 12 monitors; however, we did not necessarily consider very small subareas for irregularly shaped facilities or segregated operations. When considering these subareas, we agree that fewer than 12 monitoring sites should be appropriate. Therefore, we have provided that monitors do not need to be placed closer than 152 meters (500 feet) (or 76 meters (250 feet) if known sources are within 50 meters (162 feet) of the monitoring perimeter, which is likely for these subareas or segregated areas) with a stipulation that a minimum of 3 monitoring locations be used per subarea or segregated area. We note, however, that this distance provision does not obviate the near source extra monitoring siting requirements or the requirement to have a minimum of three monitors per subarea or segregated area.

If facility owners or operators have questions regarding the required locations of monitors for a specific application, they should contact the EPA (or designated authority) to resolve questions about acceptable monitoring placement.

vi. Compliance Time for Fenceline Monitoring Requirements

Comment: Some commenters supported EPA's proposal to provide 3 years to put a fenceline monitoring program in place, but the commenters believe that timing is unclear in the proposed regulatory language, which appears in Table 11 to subpart CC, and requested that the EPA add the initial compliance date to 40 CFR 63.658(a). One commenter stated that instituting this program for all 142 major source U.S. refineries would require considerable time. Based on their experience with their pilot study, one commenter noted that commercially available weather guards meeting the specifications of proposed Method 325A are not available and would need to be fabricated. Additionally, a commenter stated that only a limited number of laboratories in the U.S. are able to perform the necessary analyses. According to the commenter, considerable time and effort will be needed to qualify additional laboratories and to expand the capacity of existing laboratories to handle the samples from 142 refineries.

Other commenters disagreed with the EPA's proposed compliance time and suggested that the EPA shorten the timeline for implementation at refineries so that possible corrective action occurs much sooner than proposed. The commenters suggested that deployment of passive samplers can proceed more promptly than proposed, especially since the EPA has simultaneously proposed specific ''monitor siting and sample collection requirements as EPA method 325A of 40 CFR part 63, Appendix A, and specific methods analyzing the sorbent tube samples as EPA Method 325B of 40 CFR part 63, Appendix A.'' Moreover, the commenter noted, a principal reason that the EPA selected passive monitors over active monitors was due to the relative ''ease of deployment.'' The commenter claimed this ease of deployment rationale is undermined by a 3-year grace period to deploy passive monitors when the EPA is providing very specific criteria for their use. The commenter suggested that the EPA require full compliance with the passive monitoring requirement within 1 year of the effective date of the rule.

Response: While we realize that it will take some time for the refinery owners or operators to understand the final rule and develop a compliant monitoring program, we agree that in requiring the passive sampler monitoring system, we recognized the ease of implementation and deployment. Although industry commenters identified issues they faced in the API pilot study while trying to implement the monitoring method, we note that the 12 facilities that participated in the API pilot study installed the fenceline monitors and began sampling in late 2013 with relative ease and within months of obtaining the draft methods. Thus, we disagree with the suggestion that 3 years is insufficient and agree with other commenters that 3 years is in fact too long. However, we also are aware that the API pilot facilities used the direct ΔC approach proposed and did not attempt to develop site-specific monitoring programs to correct for interfering near-field sources. Although we expect that facilities could complete direct implementation of the proposed fenceline monitoring requirement within 1 year after the effective date of the rule, as suggested by some commenters, facilities that choose to develop a site-specific monitoring plan would need a longer period of time. Therefore, we are finalizing requirements that specify that facilities must begin monitoring for the official determination of ΔC values no later than 2 years after the effective date of the rule.

vii. Fenceline Monitoring Recordkeeping and Reporting Requirements

Comment: Some commenters suggested that facilities should be required to submit the monitoring data via the ERT only if they exceed the fenceline benzene concentration action level and that all remaining data should be kept on-site and available for inspection or upon request of the EPA, citing that this is consistent with EPA's semiannual NESHAP reporting of only exceptions (*i.e.*, deviations). Other commenters requested that the EPA only post the rolling annual average concentration values and not the 2-week monitoring data. These commenters indicated concern that if errors are present in the raw data that are submitted semiannually to the EPA, the data, errors and all, will be released to the public and correcting them will not take place or will not take place in a timely manner. One commenter added that there is very little useful information that can be gleaned from the raw data and posting it simply invites misunderstandings.

Commenters also stated that the EPA should adopt reporting requirements to ensure that facilities report the monitoring data appropriately. Specifically, commenters recommended that 40 CFR 63.655(h)(8)(i) should be clarified to only require reporting of valid data and cautioned that data should be processed to allow accurate calculations of annual averages to be used for reporting and evaluation. To accomplish this, commenters recommended that the rule provide 75 days from the end of a 6-month sampling period to report to the EPA, rather than the proposed 45-day period, in order to provide adequate time to obtain quality-assured results for all 2-week sampling periods.

One commenter applauded the proposal's requirements for electronic reporting of the fenceline concentration data and making the resulting information publicly available. However, the commenter recommended that the EPA consider a more truncated data reporting period that is more consistent with the associated milestones of collecting a 14-day sampling episode. As is, the commenter claimed, the proposed rule would have a lag time of up to 7.5 months between data collection and posting. The commenter indicated that data reporting on a more frequent schedule will not only provide transparency, but will provide states and local agencies with information about air quality at refineries at a frequency that could allow informed activities to address leaks much more quickly and protect public health.

Response: We disagree with the commenters who suggest that facilities only report the rolling annual average or only exceedances of the fenceline benzene concentration action level because the commenters believe there is little information to be gleaned from the raw data. Monitoring data are useful in understanding emissions, testing programs, and in determining and ensuring compliance. We generally require reporting of all test data, not just values calculated from test data and/or where a facility exceeds an emissions or operating limit. For example, when we conduct risk and technology reviews for source categories, we are adding requirements for facilities to submit performance test data into the ERT, not just performance test data that indicates an exceedance of an applicable requirement. In the Mercury and Air Toxics Rule, we require facilities to report direct measurements made with CEMS, such as gas concentrations, and we require hourly reporting of all measured and calculated emissions values (see discussion at 77 FR 9374, February 16, 2012). In particular, for the fenceline monitoring requirements in this final rule, we offer facilities options for delineating background benzene emissions and benzene emissions not attributable to the refinery, and we offer options for reduced monitoring, making it even more necessary that we have all of the data to review to ensure that testing and analyses are being done correctly and in compliance with the requirements set out in the regulations, and that root cause analyses and corrective actions are being performed where necessary. Therefore, as proposed, we are finalizing the requirements that facilities report the individual 2-week sampling period results for each monitor, in addition to the calculated ΔC values in their quarterly reporting.

Regarding commenters' concerns that facilities post accurate data and have sufficient time to perform quality assurance on the data, in the final rule, we have established provisions for how sources are to address outliers and data corrections. Additionally, as proposed, we do not require an initial report until facilities have collected 1 year of data so that facilities do not report the data until a rolling annual average value can be determined. This will allow refinery staff and analytical laboratories to iron out any issues that might arise as they implement these methods for the first time. Once this initial data collection period is complete, we anticipate that data quality issues should be infrequent. Therefore, we are providing a 45-day period following each quarterly period before facilities must submit the monitoring results, which should provide facilities adequate time to correct any data errors prior to reporting the data.

Regarding comments that suggest reporting each 2-week sample result soon after its collection, we disagree. This frequency would put undue burden on the refinery owners or operators in trying to collect, review and quality assure the data prior to reporting. However, we agree with commenters that more frequent reporting of the fenceline monitoring data would be useful. Therefore, we have revised the reporting frequency for the fenceline monitoring data to be quarterly in the final rule rather than semiannually as proposed. Additionally, we understand that there is a lot of interest in how these data will be presented to the public, and we plan to reach out to all stakeholders on appropriate approaches for presenting this information in ways that are helpful and informative.

b. Refinery MACT 2

This section provides comment and responses for the key comments received regarding the technology review amendments proposed for Refinery MACT 2. Comment summaries and the EPA's responses for additional issues raised regarding the proposed requirements resulting from our technology review are in the ''Response to Comment'' document in the public docket (Docket ID No. EPA–HQ–OAR–2010–0682).

i. FCCU

We received comments on the consideration of developments in pollution controls, the averaging time for FCCU PM limits, and the FCCU opacity limit, as discussed below.

Comment: One commenter stated that the EPA failed to consider developments in pollution controls for HAP from FCCUs for two reasons. First, the commenter contended that cost is not a valid consideration to evaluate if a ''development'' in pollution control is necessary pursuant to section 7412(d)(2), (3), (6), unless the EPA is setting a ''beyond-the-floor'' requirement.

Second, the commenter claimed that the EPA's review of developments is nearly 10 years old and misses some important pollution control improvements in the industry. For example, the commenter noted that Valero Benicia installed a combination of controls in 2012 including a scrubber, SCR and CO Boiler that combine exhaust streams from the FCCU and coking and reportedly eliminate HAP emissions entirely from these sources.

The commenter also asserted that EPA consent decrees impose lower effective limits on PM than the EPA considered under the technology review. The commenter identified the BP Whiting facility as subject to 0.7 lb PM/1,000 lbs coke burn-off at one FCCU and 0.9 lb PM/1,000 lbs coke burn-off at another and claimed these limits are lower than the 1.0 lb PM/1,000 lbs coke burn-off limit currently mandated by Refinery MACT 2.

Response: We disagree that we cannot consider costs when determining if it is necessary to revise an existing MACT standard based on developments in practices, processes and control technologies. The commenter suggests that we cannot consider costs because of the requirements in CAA section 112(d)(2) and (3) for establishing initial MACT standards and which do not allow for consideration of costs until the second, ''beyond the floor'' phase of the analysis. As discussed previously in this preamble where we respond to comments on the fenceline monitoring requirements, to the extent that the commenters are suggesting that EPA must re-perform the MACT floor analysis for purposes of setting a standard pursuant to section 112(d)(6), we note that the D.C. Circuit has rejected this argument numerous times, most recently in *National Association for Surface Finishing et al.* v. *EPA* No. 12–1459 in the U.S. Court of Appeals for the District of Columbia.

Regarding the claim that the EPA did not consider the types of controls at the Valero and BP facilities, we disagree. The control measures for both of those facilities are controls that existed at the time of the development of the MACT standard. Thus, we did not identify these technologies as developments in control technologies during the technology review. However, we did identify developments in processes or practices that reflect better control by the existing technology and we reviewed modified emission limits that reflect that better level of control. The commenter suggested that we failed to consider a level of zero when the Valero facility was able to achieve zero emissions through a combined SCR, boiler and scrubber. However, the commenter provided no information to support such a claim and we are skeptical that such a result could be achieved. We note that the SCR is designed specifically to reduce NO_X emissions, and would not be capable of reducing significantly, much less eliminating completely, HAP emissions. Similarly, based on our long-standing understanding of the processes, neither a boiler nor a scrubber could achieve such a result. Regarding the level of emissions achieved at the BP Whiting facility, we note that we evaluated control systems that can meet 0.5 lb PM/1,000 lb coke burn-off, which is a lower limit than that at BP Whiting. We determined that these were cost-effective to require for new units that are installing a new control system. However, we determined that retrofitting controls designed to meet a PM limit of 1.0 lb PM/1,000 lbs coke burn-off to now meet a limit of 0.5 lb PM/1,000 lbs coke burn-off was not cost-effective when considering PM and $PM_{2.5}$ emissions reductions. We projected the cost of the 0.5 lb PM/1,000 lbs coke burn-off limit in retrofit cases to be $23,000 per ton PM emissions reduced. To meet a limit of 0.7 lb PM/1,000 lbs coke burn-off or 0.9 lb PM/1,000 lbs coke burn-off, as is the case for BP Whiting, the retrofit costs would be similar to this 0.5 lb PM/1,000 lb coke burn-off option, but the reductions would be even less, resulting in costs over $23,000 per ton. As metal HAP content of FCCU PM is approximately 0.1 to 0.2-percent of the total PM, the cost of requiring this lower limit for existing FCCU is over $10 million per ton of metal HAP reduced. Therefore, we determined that it is not necessary to revise the PM standard for existing FCCU sources.

Comment: Refinery MACT 2 requires the owner or operator to demonstrate compliance with the PM FCCU limits by complying with the operating limits established during the performance test on a daily (*i.e.*, 24-hour) average basis. Several commenters objected to the EPA's proposal to revise this requirement to a 3-hour averaging time. Commenters restated EPA's arguments for 3-hour averaging time as: (1) Daily average could allow FCCUs to exceed limits for short periods while still complying with the daily average, (2) consistency with NSPS subpart Ja and (3) consistency with duration of testing. The commenters stated that the EPA had not provided any data that show that the daily average could allow FCCUs to exceed limits for short periods and, therefore, the EPA is using a hypothetical compliance assurance argument to change emission limits. The commenters stated that a change in emission limits is not authorized by CAA section 112 because the emission limitations in Refinery MACT 2 for FCCUs were established as daily averages following the floor and ample margin of safety requirements in section 112(d)(2) of the CAA.

The commenters also state that the EPA's additional arguments for the change to a 3-hour average are irrelevant and legally deficient. The commenters stated that the combination of a numerical emission limit and an averaging period frames the stringency of a limitation and that a reduction in either of those factors results in a significant lowering of the operating limit. The commenters conclude that the EPA has proposed to change the stringency of the requirements without justification, and the CAA requires that such a change in stringency be justified pursuant to CAA section 112(d)(6) or (f)(2). The commenters stated that increasing stringency for consistency with NSPS rules is not a criterion for a CAA section 112(d)(6) action. Rather that section requires a change to be due to ''developments.'' The only change in technology since the 2002 promulgation of Refinery MACT 2 is the availability of PM continuous emission monitoring system (CEMS), which is unproven.

One commenter noted that changing the averaging time is a very significant modification considering that the compliance limits would apply for periods of SSM. This commenter stated that it is unlikely that existing operations can consistently be in compliance with a new 3-hour average since the current daily averaging was put in place to recognize that there will be periods of operating variability that do not represent the longer term performance of an FCCU. The commenters recommended that the EPA retain the daily averaging requirement.

Response: We disagree with the commenters' statement that reducing the averaging time from a 24-hour basis to a 3-hour basis for demonstrating compliance with the FCCU PM emission limit, using operating limits established during the performance test, is a change to the MACT floor. The emission limit of 1.0 lb PM/1,000 lbs coke burn-off is the MACT floor, and we are not changing the PM emissions limit (or alternate Ni limits) in Table 1 to subpart UUU (except to remove the incremental PM limit that did not comport with the MACT floor emissions limitation).

However, whether or not it is a change from the MACT floor is not relevant. Pursuant to CAA section 112(d)(6), the EPA must revise MACT standards ''as necessary'' considering developments in practices, processes and control technologies. For this exercise, we considered any of the following to be a ''development'':

- Any add-on control technology or other equipment that was not identified and considered during development of the original MACT standards.
- Any improvements in add-on control technology or other equipment (that were identified and considered during development of the original MACT standards) that could result in additional emissions reduction.
- Any work practice or operational procedure that was not identified or considered during development of the original MACT standards.
- Any process change or pollution prevention alternative that could be broadly applied to the industry and that was not identified or considered during development of the original MACT standards.
- Any significant changes in the cost (including cost effectiveness) of applying controls (including controls the EPA considered during the development of the original MACT standards).

In determining whether there are ''developments,'' we review, among other things, EPA regulations promulgated after adoption of the MACT, such as the NSPS we identified in this instance. We identified the enhanced monitoring requirements for these operating limits as a development in practices that will help ensure FCCU owners or operators are properly operating control devices and, thus, are meeting the PM emission limit at all times. We further determined that this enhanced monitoring was cost effective and proposed that it was necessary to revise the existing standard pursuant to CAA section 112(d)(6).

While we do not have continuous PM emissions data that show actual deviations of the PM limit, we do not need such data in order to conclude that such deviations could occur when daily averages are used. The Refinery MACT 2 (*i.e.*, subpart UUU) rule requires owners or operators to establish operating limits based on three 1-hour runs during the performance test. As a matter of simple mathematics, a source could demonstrate that it is meeting the operating limit based on a 24-hour average but could be exceeding the 1.0 lb PM/1,000 lbs coke burn-off emission limit based on a 24-hour average or for one or more individual 3-hour periods during that 24-hour average. For example, an owner or operator could operate with a power input 5-percent higher than the operating limit for 23 hours, have the ESP off (zero power) for one hour, and still comply with a 24-hour average operating limit. However, it would be difficult for this same unit to meet the 1.0 lb PM/1,000 lbs coke burn-off emissions limit over a 24-hour period, and it certainly would not meet the limit for every 3-hour period during that day. As the operating limit can be established to correspond with 1.0 lb PM/1,000 lbs coke burn-off, the 5-percent higher power input would likely correspond with a 0.95 lb PM/1,000 lbs coke burn-off emissions rate (5-percent lower). Uncontrolled emissions are typically 6 to 8 lbs/1,000 lbs coke burn-off. Thus, this unit would have emissions averaging approximately 1.2 lbs PM/1,000 lbs coke burn-off during this 24-hour period [*i.e.*, (0.95*23+7)/24], but would be in compliance with the 24-hour average operating limit. The unit would obviously also be out of compliance with the 3-hour average over the period when the power was turned off. We also have concerns that the operating limits are not always linear with the emissions, so that the longer averaging times do not effectively ensure compliance with the PM emissions limit. Therefore, as proposed, we are finalizing the requirement for owners or operators to comply with the operating limits on a 3-hour basis, rather than the 24-hour basis currently in the rule.

Comment: The technology review for FCCUs resulted in the EPA proposing to remove the 30-percent opacity alternative limit for demonstrating compliance with the PM emissions limit that is available for refineries complying with the Refinery NSPS 40 CFR part 63, subpart J. Two commenters supported the EPA's proposed removal of the 30-percent opacity limit for FCCUs. Other commenters stated that current technology is good enough for a 10- or 20-percent opacity limit. On the other hand, several commenters stated that the proposed removal of the 30-percent opacity limit must meet the criteria specified in CAA section 112(d)(6) and (f)(2), which requires analysis of the statutory basis, environmental impacts, costs, operational and compliance feasibility and impacts, that the EPA has not conducted. The commenters claimed that had the EPA conducted a proper analysis, the EPA would have determined that the proposed change to remove the 30-percent opacity limit is not necessary or supportable. Additionally, these commenters stated that since the underlying PM emissions limit is unchanged, there is no emission reduction justification for this proposed change, and the change would not meet the CAA section 112(d)(6) requirement of being cost effective. The commenters also noted that processes or practices for existing FCCUs have not changed, as required for a CAA section 112(d)(6) revision.

Several commenters urged the EPA to maintain the 30-percent opacity limit for these FCCUs. As a practicable and cost-effective alternative to address the EPA's concern as to whether compliance with a 30-percent opacity limit ensures compliance with the PM emissions limit, commenters suggested annual performance tests to confirm that the FCCU is meeting the PM emissions limit, rather than performance tests every 5 years, as proposed.

One commenter stated that the EPA never intended for the opacity limit in Refinery NSPS subpart J to be used to demonstrate compliance with the PM emissions limit, but instead to assure the PM controls operate properly. The commenter stated that the EPA's conclusion that the 30-percent opacity limit may not be sufficiently stringent to ensure compliance with the underlying PM emissions limit is based on a false premise as to the purpose of the opacity standard because as the EPA states, ''Opacity of emissions is indicative of whether control equipment is properly maintained and operated.''

Several commenters stated that the proposed elimination of the 30-percent opacity limit currently in Refinery MACT 2 leaves existing FCCUs that use cyclones with no viable alternative approach to demonstrate compliance with the PM emissions limit without adding or replacing controls. They stated the other approaches for demonstrating compliance with the PM emissions limit in Refinery MACT 2 (such as development of a site-specific opacity limit) do not work for them. The commenters stated that although they believe that more frequent performance tests would show that the FCCUs are in fact meeting the PM emissions limit, the absence of the 30-percent opacity limit would force FCCUs using cyclones for PM control to install additional, costly PM controls (*e.g.,* ESPs or wet gas scrubbers). They projected that these additional controls would cost tens of millions of dollars per FCCU and would require at least 3 years of compliance time. Additionally, one commenter stated that even FCCUs with additional downstream PM controls would not be able to achieve a site-specific limit at all times and needed the availability of the alternative 30-percent opacity limit. One commenter estimated that installing an ESP to meet the proposed 10-percent opacity limit would cost approximately $121,000/ton, assuming a 32 tpy PM emission reduction. The commenter noted that the ESP would also increase GHG emissions and require more energy resources from the facility. The commenter concluded that installing an ESP is neither cost effective nor appropriate considering non-air quality environmental and health impacts and energy requirements, and recommended that the EPA maintain the current NSPS subpart J alternative limits and add additional alternative limits into Refinery MACT 2 only as optional limits for demonstrating compliance with the PM emissions limit.

Response: In promulgating Refinery MACT 2, the EPA identified the 1.0 lb PM/1,000 lbs coke burn-off limit as the MACT floor but allowed a compliance option for FCCUs subject to Refinery NSPS subpart J to comply with an opacity limit up to 30 percent with one 6-minute allowance to exceed the 30-percent opacity in any 1-hour period. As stated in the proposal, compliance studies have shown that the 30-percent opacity limit does not correlate well with the 1.0 lb PM/1,000 lbs coke burn-off limit, and that an FCCU can comply with the 30-percent opacity limit while its emissions exceed the PM emissions limit.[9] Regardless of whether the 30-percent opacity limit in Refinery NSPS subpart J was designed to ''ensure that the control device was operated properly,'' Refinery MACT 2 allows sources subject to NSPS subpart J to use the 30-percent opacity limit to demonstrate continuous compliance with the PM emissions limit. We have determined that the 30-percent opacity limit is inadequate for the purpose of demonstrating continuous compliance with the PM emissions limits in Refinery MACT 2. As such, we proposed to remove this opacity limit and require the owner or operator to either demonstrate compliance with the PM emissions limit by continuously monitoring the control device parameters established during the performance test or establish and monitor a site-specific opacity limit. For clarity, we note that we proposed to allow a site-specific opacity limit, not a 10-percent opacity limit as some commenters suggest. The site-specific opacity limit can be significantly higher than 10 percent, but it cannot be lower than 10 percent.

While the compliance study indicates that a 30-percent opacity limit does not correlate well with a 1.0 lb PM/1,000 lbs coke burn-off emissions limit, further review of this same study indicates that a 20-percent opacity limit provides a reasonable correlation with units meeting the 1.0 lb PM/1,000 lbs coke burn-off emissions limit. We also reviewed the data submitted by the commenters regarding PM emissions and opacity correlation. While the data suggest that there is variability and uncertainty in the PM/opacity correlation, the data do not support that a 30-percent opacity limit would ensure compliance even when considering the uncertainty associated with the PM/opacity correlation. Based on the variability of the 3-run average opacity limits, we determined that, if the 3-hour average opacity exceeded 20-percent, then it was highly likely (98 to 99-percent confidence) that the FCCU emissions from the unit tested would exceed the PM emissions limit.

After considering the public comments, reviewing the data submitted with those comments, and further review of the compliance study, in this final rule we are adding a 20-percent opacity limit, evaluated on a 3-hour average basis for units subject to NSPS subpart J. As we noted above, a 20-percent opacity limit provides a reasonable correlation with the PM emissions limit, and an exceedance of this 20-percent opacity limit will provide evidence that the PM emissions limit is exceeded. However, it is possible that units could still exceed the PM emissions limit while complying with the 20-percent opacity limit, if those units operate close to the 1 lb PM/1,000 lbs coke burn-off emissions limit. To address this concern, we considered the commenters' suggestion to require a performance test annually rather than once every 5 years. Some commenters suggested that this option specifically apply to FCCUs with cyclones, but this option is applicable to any control system operating very near the PM emissions limit and using an opacity limit to demonstrate continuous compliance. We have determined that the Refinery NSPS subpart J compliance procedures in Refinery MACT 2, in combination with a 20-percent opacity limit demonstrated on a 3-hour average basis and with annual performance tests when a test indicates PM emissions are greater than 80-percent of the limit (*i.e.,* 0.80 lb PM/1,000 lbs coke burn-off), will ensure continuous compliance with the PM emissions limit. FCCUs with measured PM emissions during the performance test at or below 0.80 lb PM/1000 lbs of coke burn-off will remain subject to the requirement to conduct performance tests once every 5 years, consistent with the requirements we proposed.

We do not agree with commenters that the proposed opacity revision would add significant cost or compliance burden. The control device-specific monitoring parameters that were proposed rely on parameters commonly used to control the operation of the control device, so the monitoring systems should be already available. Further, since we are merely changing the opacity limit, we expect these units will already have opacity monitoring systems needed to demonstrate compliance with the PM emissions limit and would not incur costs for new equipment.

Comment: Several commenters stated that they agree with the EPA's determination in the proposal that the current CO limits provide adequate control of HCN. Two commenters stated that there are limited HCN emissions data and that more data are needed before the Agency can appropriately determine whether an HCN standard is necessary and justified. One commenter noted that the process undertaken by the EPA to estimate HCN emissions was flawed, and likely overestimates HCN emissions significantly. Another commenter stated that they performed HCN stack testing at three refineries and subsequent modeling at two refineries and concluded that the ambient HCN emissions were well below the applicable health limits.

In contrast, some commenters expressed concerns about high HCN levels. One commenter stated that the EPA should consider re-evaluating the benefit of low NO_X emissions from the FCCU, if that is indeed the cause of higher HCN emissions, because exposing people to HCN is not acceptable. The commenter also noted that the community now also has the increased dangers of storing and transporting aqueous ammonia, which is used in some cases to achieve low NO_X emissions from the FCCU.

One commenter stated that the EPA must set stronger HCN standards on FCCU emissions because of the high release amounts reported, the fact that non-cancer risk is driven by emissions of HCN from FCCU, and the fact that the EPA has never set standards for HCN emissions. The commenter provided a report that they believe shows that the EPA has not shown that CO is a reasonable or lawful surrogate to control HCN and has not shown that the conditions necessary for a surrogate are met with regard to CO and HCN, which is an inorganic nonmetallic HAP. Further, the report indicates that SCR is a reasonable and cost effective method for controlling HCN and that the EPA failed to review and consider other viable methods to control HCN and must do so to satisfy its legal obligations in this rulemaking.

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[9] Compliance Investigations and Enforcement of Existing Air Emission Regulations at Region 5 Petroleum Refineries. U.S. Environmental Protection Agency, Region 5—Air and Radiation, Chicago, Illinois. March 9, 1998.

Response: At the time we promulgated the MACT, we determined that the control strategy used by the best performing facilities to reduce organic HAP emissions was the use of complete combustion, which occurs when the CO concentration is reduced to 500 ppmv (see the proposal for Refinery MACT 2 at 63 FR 48899, September 11, 1998). We rejected arguments that some facilities operate at CO levels well below 500 ppmv and, thus, the MACT floor should be set at a lower CO concentration because once CO concentrations reached 500 ppmv, there was no longer a correlation between reduced CO concentrations and reduced HAP concentrations. And, in fact, emissions of certain HAP, such as formaldehyde, tended to increase as CO concentrations were reduced below 500 ppmv.[10]

In the current rulemaking action, we determined at the time of the proposed rule that this also holds true for HCN emissions. That is, once CO emissions are reduced to below 500 ppmv (*i.e.,* complete combustion is achieved), we no longer see a direct correlation between CO concentrations and HCN emissions.

All of the HCN emissions data we have were reported from units operating at or below the 500 ppmv CO limit (*i.e.,* in the complete combustion range), so it is not surprising that there is not a strong correlation between CO and HCN from the FCCU ICR source test data. However, catalyst vendor data and combustion kinetic theory support the fact that, in the partial burn mode (with CO concentrations of 2 to 6-percent, which is 20,000 to 60,000 ppmv), HCN concentrations exiting the FCCU regenerator are much greater than for units using complete combustion FCCU regenerators or the concentration exiting a post-combustion device used in conjunction with a partial burn FCCU regenerator. Therefore, we maintain that complete combustion is the primary control needed to achieve controlled levels of HCN emissions.

We initially thought the higher levels of HCN emissions that were reported by sources achieving complete combustion might be due to a switch away from platinum-based combustion promoters to palladium-based combustion promoters. However, many of the units that were tested and that had some of the lowest HCN emissions used palladium-based oxygen promoters. Therefore, it appears unlikely that palladium-based catalyst promoters are linked to the higher HCN emissions. We also evaluated one commenter's argument that CO is not a good surrogate for HCN emissions, but that SCR are a reasonable and cost-effective control strategy. We are not aware of any data that suggest that an SCR removes HCN and the commenter did not provide any support for that premise. At proposal, we evaluated HCN control on units using extra oxygen or converting back to platinum-based promoters to oxidize any HCN formed. This would cause more NO_X formation, which would then require post-combustion NO_X control, such as an SCR. However, if HCN emissions are not a function of CO concentration beyond that required to achieve complete combustion (as noted by the commenter), then more aggressive combustion conditions and the use of an SCR (to remove the NO_X formed) may not be a viable control strategy. Therefore, considering all of the data currently available and the comments received regarding HCN emissions and controls, we maintain that the only proven control technique is the use of complete combustion as defined by a CO level of 500 ppmv or less. We are not establishing a more stringent CO level because, once complete combustion is achieved, (*i.e.,* CO concentrations drop below 500 ppmv), no further reduction in HCN emissions are achieved.

For the purposes of Refinery MACT 2, we consider the emission limits and operating requirements for organic HAP in Tables 8 through 14 to subpart UUU of part 63 adequate to also limit HCN emissions.

Finally, we understand concerns about the reported HCN emissions being higher than anticipated and the need for more data to better determine HCN emissions levels. To address these concerns, we are finalizing a requirement that facility owners or operators conduct a performance test for HCN from all FCCU at the same time they conduct the first PM performance test on the FCCU following promulgation of this rule. Facility owners or operators that conducted a performance test for HCN from a FCCU in response to the refinery ICR or subsequent to the 2011 Petroleum Refinery ICR following appropriate methods are not required to retest that FCCU.

4. What is the rationale for our final approach for the technology review?

a. Refinery MACT 1

We did not receive substantive comments concerning our proposal that it was not necessary to revise Refinery MACT 1 requirements for MPV, gasoline loading racks and cooling towers/heat exchange systems. Based on the rationale provided in the preamble to the proposed rule, we are taking final action concluding that it is not necessary pursuant to CAA section 112(d)(6) to revise the MACT requirements for MPV, gasoline loading racks and cooling towers/heat exchange systems emission sources at refineries.

We proposed that the options for additional wastewater controls are not cost effective and thus it was not necessary to revise the MACT for these emission sources. We received public comments suggesting that emissions from wastewater systems are higher than modeled and that we should develop additional technology standards for wastewater treatment systems regardless of cost. As we discussed in the proposal, emissions from wastewater are difficult to measure and emission estimates rely on process data and empirical correlations, which introduces uncertainty into the estimates. Although we do not have evidence, based on the process data we collected, that emissions are higher than modeled at proposal, we note that the fenceline monitoring program effectively ensures that wastewater emissions are not significantly greater than those included in the emissions inventory and modeled in the risk assessment. Furthermore, we believe that cost is a valid consideration in determining whether it is necessary within the meaning of section 112(d)(6) to revise requirements and that we are not required to establish additional controls regardless of cost. Consequently, we conclude that it is not necessary to revise the Refinery MACT 1 requirements for wastewater systems pursuant to CAA section 112(d)(6).

For storage vessels, we identified a number of options, including requiring tank fitting controls for external and internal floating roof tanks, controlling smaller tanks with lower vapor pressures and requiring additional monitoring to prevent roof landings, liquid level overfills and to identify leaking vents as developments in practices, processes and control technology. We proposed to cross-reference the storage vessel requirements in the Generic MACT (effectively requiring additional control for tank roof fittings) and to revise the

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[10] U.S. EPA, 2001. Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units—Background Information for Promulgated Standards and Response to Comments. Final Report.EPA–453/R–01–011. June. p. 1–19.

definition of Group 1 storage vessels to include smaller tanks with lower vapor pressures. We received comments that we could have required additional controls on tanks and monitoring for landings, overfills and leaking vents described above. We also received comments related to clarifications of specific rule references and overlap provisions. We addressed these comments in the ‘‘Response to Comments’’ document, and we maintain that the additional control options described by the commenters (tank roof landing/degassing requirements or use of geodesic domes to retrofit external floating roofs) are not cost-effective. Consequently, based on the rationale provided in the preamble to the proposed rule and our consideration of public comments, we are finalizing the requirements as proposed with minor clarifications of the rule references. However, as with wastewater systems, we note that the fenceline monitoring program will ensure that the owner or operator is effectively managing fugitive emissions sources and should detect landings, overfills, and leaking vents.

For equipment leaks, we identified specific developments in practices, processes and control technologies that included requiring repair of leaking components at lower leak definitions, requiring monitoring of connectors, and allowing the use of the optical imaging camera as an alternative method of monitoring for leaks. We proposed to establish an alternative method for refineries to meet LDAR requirements in Refinery MACT 1. This alternative would allow refineries to monitor for leaks via optical gas imaging in place of EPA Method 21, using monitoring requirements to be specified in a not yet proposed appendix K to 40 CFR part 60. However, the development of appendix K is taking longer than anticipated. Therefore, we are not finalizing this alternative monitoring method in Refinery MACT 1.

We received comments suggesting that additional requirements be imposed to further reduce emissions from leaking equipment components, such as requiring ‘‘leakless’’ equipment, reducing the leak threshold, and eliminating delay of repair provisions. As provided in the ‘‘Response to Comments’’ document, we do not agree that these additional requirements are cost-effective. Based on the rationale provided in the preamble to the proposed rule and our consideration of public comments, we conclude that it is not necessary to revise the Refinery MACT 1 requirements for equipment leaks. Again, however, the fenceline monitoring program is intended to ensure that large leaks from fugitive emissions sources, including equipment leaks, are more quickly identified and repaired, thereby helping to reduce emissions from leaking equipment components.

For marine vessel loading, we identified control of marine vessel loading operations with HAP emissions of less than 10/25 tpy and the use of lean oil absorption systems as developments that we considered in the technology review. We proposed to amend 40 CFR part 63, subpart Y to require small marine vessel loading operations (*i.e.,* operations with HAP emissions less than 10/25 tpy) and offshore marine vessel loading operations to use submerged filling based on the cargo filling line requirements in 46 CFR 153.282. We received comments that other options considered during the technology review of the standard were cost-effective for small marine vessel loading operations and should be required. As provided in the ‘‘Response to Comments,’’ we continue to believe those other controls are not cost-effective because of the high costs of controls for limited additional organic HAP emission reduction. Therefore, we are finalizing these amendments as proposed.

Finally, we proposed that it was necessary to revise the MACT to require fenceline monitoring as a means to manage fugitive emissions from the entire petroleum refinery, which includes sources such as wastewater collection and treatment operations, equipment leaks and storage vessels. We received numerous comments regarding the proposed requirement to conduct fenceline monitoring, many of which we address above and the remainder of which we respond to in the ‘‘Response to Comments’’ document. After considering comments, we maintain that the proposed work practice standard is authorized under section 112 of the CAA and will improve fugitive management at the refinery. Therefore, we are finalizing the key components of fenceline monitoring work practice as proposed. These requirements include the use of passive diffusive tube samplers (although we are providing a mechanism to request approval for alternative monitoring systems provided certain criteria are met), the 9 $\mu g/m^3$ on a rolling annual average basis action level, and the need to perform corrective action to comply with the action level.

Based on public comments received, we are making numerous revisions to clarify the fenceline monitor siting requirements. This includes provisions to allow siting of monitors within the property boundary as long as all emissions sources at the refinery are included within the monitoring perimeter. We are also clarifying that we do not consider public roads or public waterways that bisect a refinery to be property boundaries, and owners or operators do not need to place monitors along the internal public right-of-ways. We are also providing provisions to allow fixed placement of monitors at 500 feet intervals (with a minimum of 3 monitors) for subareas or segregated areas. If an emissions source is near the monitoring perimeter, an additional monitor siting requirement would still apply. The 500 feet provision is provided to reduce burden for facilities with irregular shapes or noncontiguous property areas that we did not fully consider at proposal.

We also received comments on the compliance time and reporting requirements associated with the fenceline monitoring provisions. Upon consideration of public comments, we have revised the compliance period to 2 years after the effective date of the final rule. Thus, beginning no later than 2 years after the effective date of the rule, the source must have a fenceline monitoring system that is collecting samples such that the first rolling annual average ΔC value would be completed no later than 3 years after the effective date of the final rule. Facilities will have 45 days after the completion of the first year of sampling, as proposed, to submit the initial data set. We are reducing the proposed compliance period from 3 years to 2 years because the passive diffusive tube monitors are easy to deploy and pilot study demonstrations indicate that significant time is not needed to deploy the monitors. However, the reduced compliance period still provides time to resolve site-specific monitor placement issues and to provide time to develop and implement a site-specific monitoring plan, if needed. We are increasing the fenceline monitoring reporting frequency (after the first year of data collection) from semiannually to quarterly to provide more timely dissemination of the data collected via this monitoring program.

b. Refinery MACT 2

We proposed to revise Refinery MACT 2 to incorporate the developments in monitoring practices and control technologies reflected in the Refinery NSPS subpart Ja limits and monitoring provisions (73 FR 35838, June 24, 2008). We are finalizing most of these provisions as proposed. Specifically, we are incorporating the

Refinery NSPS subpart Ja PM limit for new FCCU sources. We are also finalizing compliance options for FCCU that are not subject to Refinery NSPS subpart J or Ja. These options would allow such sources to elect to comply with the Refinery NSPS subpart Ja monitoring provisions to demonstrate compliance with the emissions PM limit. We are revising the averaging period for the control device operating limits or site-specific opacity limits to be on a 3-hour average basis in order to more directly link the operating limit to the duration of the performance test runs, on which they are based, as proposed. We are incorporating additional control device-specific monitoring alternatives for various control devices on FCCU, including BLD monitoring as an option to COMS for owners or operators of FCCU using fabric filter-type control systems and total power and secondary current operating limits for owners or operators of ESPs. We are adding an additional requirement to perform daily checks of the air or water pressure to atomizing spray nozzles for owners or operators of FCCU wet gas scrubbers not subject to the pressure drop operating limit, as proposed. Finally, we finalizing requirements to conduct a performance test at least once every 5 years for all FCCU, as proposed. These requirements are being finalized to ensure that control devices are continuously operated in a manner similar to the operating conditions of the performance test and to ensure that the emissions limits, which are assessed based on the results of three 1-hour test runs, are achieved at all times.

We also proposed to eliminate the Refinery NSPS subpart J compliance option that allows refineries to meet the 30-percent opacity emissions limit requirement and revise the MACT to include control device operating limits or site-specific opacity limits identical to those required in Refinery NSPS subpart Ja. We received numerous comments, particularly from owners or operators of FCCU that employ tertiary cyclones to control FCCU PM emissions. According to the commenters, opacity is not a direct indicator of PM emissions because finer particles will increase opacity readings without a corresponding mass increase in PM emissions. Additionally, the commenters stated that the site-specific opacity limit generally leads to a site-specific operating limit of 10-percent opacity, which is too stringent and does not adequately account for variability between PM emissions and opacity readings. According to the commenters, FCCU with tertiary cyclones would need to be retrofitted with expensive and costly controls in order to meet the 10-percent opacity limit, even though they are meeting the 1 lb/1000 lbs coke burn PM emissions limit. It was not our intent to require units to retrofit their controls simply to meet the site-specific opacity limit. However, the existing 30-percent opacity limit in the subpart J compliance option is not adequate to ensure compliance with the PM emissions limit at all times. After reviewing the public comments and available data, we determined that, rather than removing the subpart J compliance option altogether, it is sufficient to add an opacity operating limit of 20-percent opacity determined on a 3-hour average basis to the existing subpart J compliance option and to require units complying with this operating limit to conduct annual performance tests (rather than one every 5 years) when the PM emissions measured during the source test are greater than 0.80 lb PM/1,000 lbs coke burn-off. These provisions improve assurance that these units are, in fact, achieving the required PM emissions limitation without requiring units to retrofit controls due to variability in the correlation of PM emissions and opacity.

We did not propose to revise the organic HAP emissions limits for FCCU to further address HCN emissions. We received numerous comments on this issue. We continue to believe that complete combustion is the appropriate control needed to control HCN emissions. Consequently, for the purposes of Refinery MACT 2, we are not changing the MACT standards to further reduce emissions of HCN. However, we understand that there are uncertainties and high variability in HCN emissions measured from FCCU. In order to address the need for more data to better characterize HCN emissions levels, we are finalizing a requirement for refinery owners or operators to conduct a performance test for HCN from all FCCU (except those units that were tested previously using acceptable methods as outlined in the 2011 Refinery ICR) during the first PM test required as part of the on-going compliance requirements for FCCU metal HAP emissions. These data will be useful to the EPA in understanding HCN emissions from FCU and may help to inform future regulatory reviews for this source category.

We proposed that there have been no developments in practices, processes, and control technologies for CRU based on our technology review and that therefore it is not necessary to revise these standards. Based on the rationale provided in the preamble to the proposed rule and our consideration of public comments, we are finalizing our conclusion.

For SRU, we identified the Refinery NSPS subpart Ja allowance for oxygen-enriched air as a development in practice and we proposed that it was necessary to revise the MACT to allow SRU to comply with Refinery subpart Ja as a means of complying with Refinery MACT 2. The key issue identified by commenters was that Refinery NSPS subpart Ja includes a flow monitoring alternative for determining the average oxygen concentration in the enriched air stream and that this was not included in the proposed amendments to Refinery MACT 2. This was an oversight on our part. We are, based on the rationale provided in the preamble to the proposed rule and our consideration of public comments, finalizing the SRU revisions as proposed but with inclusion of the flow monitoring alternative provisions that are in Refinery NSPS subpart Ja for this source.

C. Refinery MACT Amendments Pursuant to CAA Section 112(d)(2) and (d)(3)

1. What did we propose pursuant to CAA section 112(d)(2) and (d)(3) for the Petroleum Refinery source categories?

We proposed the following revisions to the Refinery MACT 1 and 2 standards pursuant to CAA section 112(d)(2) and (3)[11]: (1) Adding MACT standards for DCU decoking operations; (2) revising the CRU purge vent pressure exemption; (3) adding operational requirements for flares used as APCD in Refinery MACT 1 and 2; and (4) adding requirements and clarifications for vent control bypasses in Refinery MACT 1.

For DCU, we proposed to require that prior to venting or draining, each coke drum must be depressured to a closed blowdown system until the coke drum vessel pressure is 2 psig or less. As proposed, the 2 psig limit would apply to each vessel opening/venting/draining event at new or existing affected DCU facilities.

For the CRU, we proposed to require that any emissions during the active

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[11] The EPA has authority under CAA section 112(d)(2) and (d)(3) to set MACT standards for previously unregulated emission points. EPA also retains the discretion to revise a MACT standard under the authority of section 112(d)(2) and (3), *see Portland Cement Ass'n* v. *EPA,* 665 F.3d 177, 189 (D.C. Cir. 2011), such as when it identifies an error in the original standard. See also *Medical Waste Institute* v. *EPA,* 645 F. 3d at 426 (upholding EPA action establishing MACT floors, based on post-compliance data, when originally-established floors were improperly established).

purging or depressuring of CRU vessels meet the applicable organic HAP emission limitations in Tables 15 and 16 to subpart UUU regardless of the vessel pressure.

For flares, we proposed to remove cross references to the General Provisions requirements for flares used as control devices at 40 CFR 63.11(b) and to incorporate enhanced flare operational requirements directly into the Refinery MACT rules. The proposed rule amendments included:

- A ban on flaring of halogenated vent streams.
- A requirement to operate with continuously lit pilot flames at all times and to equip the pilot system with an automated device to relight the pilot if it is extinguished.
- A requirement to operate with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours and to monitor for visible emissions daily.
- A requirement to operate with the flare tip velocity less than 60-feet-per-second or the velocity limit calculated by an equation provided in the proposed rule.
- A requirement to meet one of three combustion zone gas properties operating limits based on the net heating value, lower flammability limit, or combustion concentration. Owners or operators could elect to comply with any one of the three limits at any time. Two separate sets of operating limits were proposed: One for gas streams not meeting all three ''hydrogen-olefin interaction criteria'' specified in the rule and a more stringent set of limits for gas streams meeting all three hydrogen-olefin interaction criteria. The combustion zone net heating value considered steam assist rates but not ''perimeter air'' assist rates.
- For air-assisted flares, a requirement to meet an additional ''dilution parameter'' operating limit determined based on the combustion zone net heating values above, the diameter of the flare and the perimeter air assist rates.

The proposed amendments for flares also included detailed monitoring requirements to determine these operating parameters either through continuous parameter monitoring systems or grab sampling, detailed calculation instructions for determining these parameters on a 15-minute block average, and detailed recordkeeping and reporting requirements. We also proposed provisions to allow owners or operators to request alternative emissions limitations that would apply in place of the proposed operating limits.

We proposed to revise the definition of MPV to remove the current exclusion for in situ sampling systems (onstream analyzers). We also proposed to limit the exclusion for gaseous streams routed to a fuel gas system to apply only to those systems for which any flares receiving gas from the fuel gas system are in compliance with the proposed flare monitoring and operating limits. We note that we also proposed revisions related to monitoring of bypass lines, but these revisions were proposed to address concerns related to SSM releases and are described in further detail in section IV.D. of this preamble.

We proposed that emissions of HAP may not be discharged to the atmosphere from PRD in organic HAP service to address concerns related to SSM releases. To ensure compliance with this proposed amendment, we proposed to require that sources monitor PRD using a system that is capable of identifying and recording the time and duration of each pressure release and of notifying operators that a pressure release has occurred. This proposed requirement was addressed in section IV.A.4. of the preamble for the proposal.

2. How did the revisions pursuant to CAA section 112(d)(2) and (3) change since proposal?

We proposed identical standards for existing and new DCU decoking operations, but we are finalizing standards for new and existing sources that are not identical. We are finalizing provisions that will require owners or operators of existing DCU sources to comply with a 2 psig limit averaged over 60 cycles (*i.e.,* 60 venting events), rather than meet the 2 psig limit on a per venting event basis, as proposed. We are finalizing provisions that will require owners or operators of new DCU sources to comply with a 2.0 psig limit on a per event, not-to-exceed basis. We are adding one significant digit to the limit for new DCU affected sources because our re-review of permit requirements conducted in response to comments identified that the best performing DCU source is required to comply with a 2.0 psig limit on a per event basis. In response to comments regarding the proposed prohibition on draining prior to achieving the pressure limit, we are finalizing specific provisions for DCU with water overflow design and for double quenching.

For flares, we are not finalizing the ban that we proposed on halogenated vent streams and we are not finalizing the proposed requirement to equip the flare pilot system with an automated device to relight an extinguished pilot. We are revising the MACT to include the proposed no visible emissions limit and the flare tip velocity limit as direct emissions limits only when the flare vent gas flow rate is below the smokeless capacity of the flare. Under the revised standard, when the flare is operating above the smokeless capacity, an exceedance of the no visible emission limit and/or flare tip velocity limit is not a violation of the standard but instead triggers a work practice standard. Flares operate above the smokeless capacity only when there is an emergency release event and thus the work practice standard is intended to address emissions during such emergency release events. (See section IV.D. of this preamble for more details regarding this work practice standard). We are also adding provisions that would allow sources to use video surveillance of the flare as an alternative to daily Method 22 visible emissions observations.

For flares, we are also simplifying the combustion zone gas property operating limits by finalizing a requirement only for the net heating value of the combustion zone gas. We are finalizing requirements that flares meet a minimum operating limit of 270 BTU/scf NHVcz on a 15-minute average, as proposed, and we are allowing refinery owners or operators to use a corrected heat content of 1212 BTU/scf for hydrogen to demonstrate compliance with this operating limit. We are not finalizing separate combustion zone operating limits for gases meeting the hydrogen-olefin interaction criteria that were proposed. We are also not finalizing the alternative combustion zone operating limits based on lower flammability limit or combustibles concentration.

We are finalizing ''dilution parameter'' requirements for air-assisted flares, but we are providing a limit only for the net heating value dilution parameter. Similar to the requirements we are finalizing for the combustion zone parameters, we are finalizing requirements that flares meet a minimum operating limit of 22 BTU/ft^2 NHV_{dil} on a 15-minute average, as proposed, and we are allowing refinery owners or operators to use a corrected heat content of 1,212 BTU/scf for hydrogen to demonstrate compliance with this operating limit. We are not finalizing separate dilution parameter operating limits for gases meeting the hydrogen-olefin interaction criteria that were proposed. We are also not finalizing the alternative dilution parameter operating limits based on lower flammability limit or combustibles concentration.

We are providing an alternative to use initial sampling period and process knowledge for flares in dedicated service as an alternative to continuous or on-going grab sample requirements for determining waste gas net heat content.

We are finalizing revisions to the definition of MPV, as proposed.

We are establishing work practice standards that apply to PRD releases in place of the proposed prohibition on PRD releases to the atmosphere. The work practice standards that we are finalizing for PRD require refiners to establish proactive, preventative measures for each PRD to identify and correct direct releases of HAP to the atmosphere as a result of pressure release events. Over time, these proactive measures will reduce the occurrence of releases and the magnitude of releases when they occur, while avoiding the environmental disbenefits of having additional flare capacity on standby to control these unpredictable and infrequent events. Refinery owners or operators will be required to perform a root cause analysis/corrective action following such pressure release events. In addition, a second release event in a 3-year period from the same PRD with the same root cause on the same equipment is a deviation of the work practice standard. A third release event in a 3-year period from the same PRD is a deviation of the work practice standard regardless of the root cause. PRD release events related to force majeure events are not considered in these hard limits.

3. What key comments did we receive on the proposed revisions pursuant to CAA section 112(d)(2) and (3) and what are our responses?

i. DCU

Comment: Several commenters argued that the EPA incorrectly set the MACT floor emission limitation for DCU. Commenters noted that CAA section 112(d)(3)(A) states that the MACT limit for existing sources ‘‘shall not be less stringent, and may be more stringent than the average emission limitation achieved by the best performing 12-percent of the existing sources’’ excluding those first achieving that level within 18 months prior to proposal or 30 months prior to promulgation, whichever is later. According to the commenters, the EPA failed to follow this procedure in setting the 2 psig vent limit as a MACT floor because the EPA incorrectly considered permit limits and other non-performance based criteria instead of basing the MACT floor on the actual performance of sources. Commenters stated that the EPA improperly considered permit limits that should have been excluded from consideration, as well as considering permit limits for closed facilities instead of using more accurate data from operating DCUs at sources that submitted actual emissions data. Specifically, commenters stated that the DCU at the non-operational plant (Hovensa) should not be included. One commenter noted that they operate one of the South Coast DCU listed as subject to a 2 psig limit and asserted that it does not currently meet that emission limitation. The commenter claimed that significant capital investment would be required in order for the DCU to comply with the 2 psig limit. According to one commenter, data for six of the eight DCU they claim the EPA considered for the MACT floor should not be counted in determining the limit that represents the average emission limitation actually achieved 18 months prior to the proposal.

Response: CAA section 112(d)(3)(A) states that the existing source standard shall not be less stringent than the average emission limitation achieved by the best performing 12-percent of the existing sources (for which the Administrator has emissions information), excluding those sources that have, within 18 months before the emission standard is proposed or within 30 months before such standard is promulgated, whichever is later, first achieved a level of emission rate or emission reduction which complies, or would comply if the source is not subject to such standard, with the lowest achievable emission rate (as defined by section 171) applicable to the source category and prevailing at the time, in the category or subcategory for categories and subcategories with 30 or more sources. We consider a 2 psig emissions limitation to be equivalent to the lowest achievable emission rate (LAER) emission limits. Thus, we agree with the commenter that sources that first meet the 2 psig limit on or after December 30, 2012, should be excluded from the MACT floor analysis. We also agree that under CAA section 112(d)(3)(A), the MACT floor analysis focuses on those sources that are achieving the emission limit (*i.e.,* the emission limitation ‘‘achieved by . . . ’’). The EPA has previously determined that the 6th-percentile unit is a reasonable estimate of the average emission limitation achieved by the best performing 12-percent of sources especially when averaging across units with and without control requirements. As noted in our DCU MACT floor analysis memorandum (Docket ID No. EPA–HQ–OAR–2010–0682–0203), the 6th-percentile is represented by the fifth-best performing DCU. If we exclude the two South Coast refineries and the two Marathon Garyville DCU because these sources were not implementing the 2 psig permit limit prior to December 30, 2012, the fifth-best performing DCU would be represented by the Bay Area refineries (4.6 psig). However, based on the 2011 Petroleum Refinery ICR responses, 25 out of 75 (33-percent) DCU have a ‘‘typical coke drum pressure when first vented to the atmosphere’’ of 2 psig or less and 10 out of 75 (13-percent) DCU have a ‘‘typical coke drum pressure when first vented to the atmosphere’’ of 1 psig or less. While we acknowledge that these data represent ‘‘typical’’ operations and not necessarily a never-to-be-exceeded emissions limitation, we conclude that this information is sufficient for us to conclude that the average emission limitation achieved by the best performing 12-percent of sources is consistent with a 2 psig emissions limitation. This is because facility owners or operators commonly target to operate at approximately half the allowable emissions limit to ensure that they can comply with the emissions limit at all times. Therefore, we maintain that an average venting pressure of 2 psig is the MACT floor level for decoking operation at existing sources based on the ICR responses and considering the average performance expected.

Comment: Four commenters suggested that the 2 psig limit, if finalized, should be based on a rolling 30-day average per DCU rather than a never to be exceeded ‘‘instantaneous’’ standard. According to the commenters, an instantaneous standard is unnecessary to address HAPs with chronic health impacts and adds cost and compliance challenges. According to the commenters, chronic health impacts are not materially affected by short-term variability, but instead depend on the average concentration of exposure over a 70-year lifetime; therefore, there is no health based or environmental reason for requiring an instantaneous limit. The commenters noted that there would be additional capital costs to comply with a 2 psig not-to-be-exceeded limit compared to a 30-day average 2 psig limit vent pressure. One commenter specifically requested that the EPA also confirm that a pressure of 2.4 psig is compliant with the 2 psig limit vent pressure. Another commenter also requested clarification that the vent pressure can be rounded to one significant figure when determining compliance.

Response: For new sources, the MACT floor emission limit for DCU is based on the best-performing source. Based on this and other comments received, we again reviewed existing permit conditions. Based on this review, we found that one of the permit requirements specified the pressure limit as 2.0 psig for each coke drum venting event. Therefore, we are finalizing the new source MACT floor as 2.0 psig on a per coke drum venting event basis.

As discussed in response to the previous comment, we are basing the MACT floor for existing source DCU on responses we received from the 2011 Petroleum Refinery ICR. Because the ICR requested the ''typical coke drum pressure when first vented to the atmosphere,'' we do not consider the information provided in ICR responses to reflect a ''never-to-be-exceeded'' limit. Therefore, we evaluated whether it is reasonable to allow averaging, and if so, what averaging period should be provided.

Health risks are not considered in establishing MACT requirements, so we do not consider the argument that chronic effects are evaluated over a 70-year period to be relevant to a determination of the MACT floor. However, a primary consideration regarding averaging periods is how the averaging period was considered in setting the floor and whether the intended reductions will occur under a different averaging period. According to the heat balance method for estimating DCU emissions, DCU decoking operations emissions are directly proportional to the average bed temperature. While the relationship is not exactly linear, the average bed temperature is expected to be a function of the venting pressure. Moreover, the shape of the pressure-temperature correlation curve is such that the emissions at 6 psig are almost exactly but not quite three times the emissions at 2 psig. Given the expected linearity of the emissions with venting pressures, we are not concerned with an occasional venting event above 2 psig because the average emissions from a facility meeting an average 2 psig pressure limit would be identical to the emissions achieved by a facility that vented each time at 2 psig. That is, given the expected linearity in the projected DCU emissions to the venting pressure, we conclude that it is reasonable to allow averaging across events and that the precise averaging period is not a critical concern.

Most industry commenters requested a 30-day average. However, different facilities have different numbers of DCU, different numbers of drums per DCU and different cycle times. Consequently, basing the averaging period across a given time period would result in significantly different number of venting events included in a 30-day average for different facilities and generally provide more flexibility to larger refineries and less flexibility to smaller refineries. Based on the ICR responses, almost half of all DCU operate with two drums and about 90-percent of DCU have two to four coke drums; however, a few DCU have six or even eight drums. Also, based on the ICR responses, the average complete coke drum cycle time is 32 hours, but can be as short as 18 hours and as long as 48 hours. Reviewing the ICR responses, we found that a 30-day average would include 30 events for some facilities and more than 250 events at other facilities.

Since the existing source MACT standards apply ''in combination'' to ''all releases associated with decoking operations'' at a given facility, we determined that it was reasonable to consider an averaging period that applies to the number of venting events from all coke drums at the facility rather than to all coke drums for a specific DCU for a specified period of time. This provides a more consistent basis for the averaging period and allows the same operational flexibility for small refineries as large refineries. Based on the ICR responses, the median (typical) DCU has 60 venting events in a 30-day period. Providing an averaging period of 60 venting events provides a more consistent averaging basis for all facilities, regardless of the number of DCU at the facility and the number of drums and cycle times for different DCU. Additionally, it eliminates issues with respect to how to handle operating days versus non-operating days, *e.g.,* in the event of a turn-around resulting in a limited number of venting events in a 30-calendar day period. Therefore, we are establishing a 2 psig limit based on a 60-event average considering all coke drum venting events at an existing source and we are finalizing a 2.0 psig limit on a per coke drum venting event for DCU at new sources.

We have consistently maintained our policy to round to the last digit provided in the emission limit, a pressure of 2.4 psig would round to 2 psig and would be compliant with a requirement to depressure each coke drum to a closed blowdown system until the coke drum vessel pressure is 2 psig or less, but it would not be compliant with the revised new source provision to depressure until the coke drum vessel pressure is 2.0 psig or less. A coke drum pressure of 2.04, however, would be compliant with the revised new source requirement pressure limit of 2.0 psig.

ii. Refinery Flares

Comment: Several commenters suggested that the proposed flare operating limits were too complex. The commenters recommended that the EPA eliminate the dual flare combustion zone heat content limits related to the proposed hydrogen-olefin interaction criteria and instead finalize a single combustion zone net heating value of approximately 200 BTU/scf, which would minimize the unnecessary burning of supplemental gas but still ensure good combustion efficiency.

A few commenters suggested that the EPA based the proposed combustion zone limits on an invalid data analysis, that the 1 minute PFTIR data should not be used to establish combustion efficiency correlations, and that the emission limits should be set so as to provide an equal chance of false positives and negatives. A few commenters suggested that the EPA should assign hydrogen a heating value of 1,212 BTU/scf to more accurately reflect its flammability in a NHV basis and that doing so is consistent with some recent flare consent decrees and would help reduce natural gas supplementation for facilities complying only with the NHVcz metric.

Several commenters suggested that neither scientific literature nor the available flare test data support the EPA's claim of an adverse hydrogen-olefin interaction on combustion efficiency and that the EPA should not finalize the more restrictive combustion zone operating limits for all flare types. These commenters suggested that the EPA did not provide any evidence the assumed hydrogen-olefin effect actually exists; that statistical analysis demonstrates the EPA developed their limit based on random differences in data; that the PFTIR data analysis method of using the individual minute-by-minute data instead of the test average data is flawed and leads to invalid conclusions; and that proper analysis of the data demonstrates the more stringent operating limits for hydrogen-olefin conditions cannot be supported.

Some commenters suggested that there is evidence to support more stringent flare combustion zone limits for a narrowly defined high concentration propylene-only condition as outlined in some of the recent flare consent decrees but that the flare test data do not support more stringent operating limits for the proposed hydrogen-olefins criteria by the EPA. Additionally, one commenter suggested that if the EPA decides to proceed with the more restrictive combustion zone limits for the hydrogen-olefins interaction cases then the final rule should not expand beyond an interaction between hydrogen and propylene.

Several commenters suggested that the proposed 15-minute feed forward averaging time for flares (*e.g.,* combustion zone parameters, air-assist dilution parameters and associated flow rates) is arbitrary, unrealistic and unworkable and that the feed forward compliance determination should not be finalized and, if it is finalized, the averaging time should be extended to 1-hour, 3-hour, or 24-hour. To support these suggested averaging periods, commenters claimed that typical standards for combustion devices are averaged over these suggested timeframes, noting as an example, recent refinery flare consent decrees that contain a 3-hour average. The commenters also asserted that both a GC and calorimeter will be needed to obtain data rapidly enough to try and maintain a 15-minute average; that the feed forward approach requires calculation artifices to attempt to correct for the fact that compliance cannot be determined until the averaging period is over; and that a longer averaging time is needed for instrument and control response time.

Response: In addressing these comments, we further analyzed the flare emissions test data. First, to address concerns that the minute-by-minute analysis produced flawed results, we re-compiled the data into approximate ''15-minute averages'' to the extent practical based on the duration of a given test run (*e.g.,* a 10-minute run was used as 1 run and a 32-minute run was divided into 2 runs of 16 minutes each). We do not find significant differences in the data or that different conclusions would be drawn from the data based on this approach as compared with the minute-by-minute analysis used for the proposed rule.

Next, we evaluated the 15-minute run data using the normal net heating value for hydrogen of 274 Btu/scf, which is the value we used in the analysis for the proposed rule and also evaluated the data using the 1,212 Btu/scf, the value recommended by some commenters. The 1,212 Btu/scf value is based on a comparison between the lower flammability limit and net heating value of hydrogen compared to light organic compounds and has been used in several consent decrees to which the EPA is a party. Based on our analysis, we determined that using a 1,212 Btu/scf value for hydrogen greatly improves the correlation between combustion efficiency and the combustion zone net heating value over the entire array of data. Using the net heating value of 1,212 Btu/scf for hydrogen also greatly reduced the number of ''type 2 failures'' (instances when the combustion efficiency is high, but the gas does not meet the NHVcz limit). One of the primary motivations for the proposed approach to provide alternative limits based on lower flammability limits and combustibles concentrations was to reduce these type 2 failures. Therefore, we proposed all three of these parameters (*i.e.,* NHVcz, LFL and total combustibles) and allowed flare owners or operators to comply with any of the parameter limits at any time. When using the net heating value of 1,212 Btu/scf for hydrogen, the other two alternatives no longer provide any improvement in the ability to predict good flare performance. Consequently, we are simplifying the operating limits to use only NHVcz.

Next, we re-evaluated whether to finalize the proposed dual combustion zone operating limits for refinery flares that met certain hydrogen-olefins interactions or to finalize a single combustion zone net heating value limit. The newly re-compiled PFTIR run average flare dataset suggests that higher operating limits may be appropriate for some olefin-hydrogen mixtures. However, the dataset using 15-minute test average runs is much smaller than the set using 1-minute runs and thus creates a greater level of uncertainty. In addition, we cannot definitively conclude that a dual combustion zone limit for refinery flares meeting certain hydrogen-olefins interactions is appropriate given these uncertainties. Thus, in order to minimize these uncertainties and streamline the compliance requirements, we used all of the 15-minute test run average data together as a single dataset in an effort to determine an appropriate, singular combustion zone net heating value operational limit.

Finally, we conducted a Monte Carlo analysis to help assess the impacts of extending the averaging time on the test average flare dataset of 15-minute runs to 1-hour or 3-hour averaging time alternatives. While we consider it reasonable to provide a longer averaging time for logistical reasons, the Monte Carlo analysis demonstrated, consistent with concerns described in our proposal, that short periods of poor performance can dramatically limit the ability of a flare to achieve the desired control efficiency. Consequently, we find it necessary to finalize the proposed 15-minute averaging period to ensure that the 98-percent control efficiency for flares is achieved at all times. However, we understand that flare vent gas flow and composition are variable. While a short averaging time is needed to ensure adequate control given this variability, we also understand the complications that this variability places on flare process control in efforts to meet the NHVcz limit. Therefore, we are clarifying that the 270 Btu/scf NHVcz value is an operational limit that must be calculated according to the requirements in this rule. We also clarify that compliance with this operational limit must be evaluated using the equations and calculation methods provided in the rule. We proposed a feed forward calculation method to allow refinery owners or operators a means by which to adjust steam (or air) and, if necessary, supplemental natural gas flow, in order to meet the limit. In other words, ''feed forward'' refers to the fact that the rule requires the refinery owners or operators to use the net heating value of the vent gas (NHVvg) going into the flare in one 15-minute period to adjust the assist media (*i.e.,* steam or air) and/or the supplemental gas in the next 15-minute period, as necessary for the equation in the rule to calculate an NHVcz limit of 270 BTU/scf or greater. We recognize that when a subsequent measurement value is determined, the instantaneous NHVcz based on that compositional analysis and the flow rates that exist at the time may not be above 270 Btu/scf. We clarify that this is not a deviation of the operating limit. Rather, the owner or operator is only required to make operational adjustments based on that information to achieve, at a minimum, the net heating value limit for the subsequent 15-minute block average. Failure to make adjustments to assist media or supplemental natural gas using the equation provided for calculating an NHVcz limit of 270 BTU/scf, using the NHVvg from the previous period, would be a deviation of the operating limit.

Alternatively, if the owner or operator is able to directly measure the NHVvg on a more frequent basis, such as with a calorimeter (and optional hydrogen analyzer), the process control system is able to adjust more quickly, and the owner or operator can make adjustments to assist media or supplemental natural gas more quickly. In this manner, the owner or operator is not limited by relying on NHVvg data that may not represent the current conditions. Therefore, the owner or operator may opt to use the NHVvg from the same period to comply with the operating limit.

Based on the results of all of our analyses, the EPA is finalizing a single minimum NHVcz operating limit for flares subject to the Petroleum Refinery MACT standards of 270 BTU/scf during any 15-minute period. The agency believes, given the results from the various data analyses conducted, that this operating limit is appropriate, reasonable and will ensure that refinery flares meet 98-percent destruction efficiency at all times when operated in concert with the other suite of requirements refinery flares need to achieve (*e.g.,* flare tip velocity requirements, visible emissions requirements, and continuously lit pilot flame requirements). For more detail regarding our data re-analysis, please see the memorandum titled ''Flare Control Option Impacts for Final Refinery Sector Rule'' in Docket ID No. EPA–HQ–OAR–2010–0682.

Comment: Numerous commenters objected to the proposed requirements to have the velocity and visible emissions limits apply at all times for flares. Commenters suggested that flares are not designed to meet the visible emissions and flare tip velocity requirements when being operated beyond their smokeless capacity and suggested several alternative approaches: remove the visible emissions and flare tip velocity requirements from the rule altogether; exempt flares from these requirements during emergencies; or add a requirement to maintain a visible flame present at all times or include a work practice standard in the rule when flares are operated beyond their smokeless capacity at full hydraulic load. The commenters identified full hydraulic load as the maximum flow the flare can receive based on the piping diameter of the flare header and operating pressure of processes connected to the flare header system. They also specified that full hydraulic load would only occur if all sources connected to the flare header vented at the same time, which might result from an emergency shutdown due to a plant-wide power failure. According to commenters, flares are typically designed to operate in a smokeless manner at 20 to 30-percent of full hydraulic load. Thus, they claimed, flares have two different design capacities: A ''smokeless capacity'' to handle normal operations and typical process variations and a ''hydraulic load capacity'' to handle very large volumes of gases discharged to the flare as a result of an emergency shutdown. According to commenters, this is inherent in all flare designs and it has not previously been an issue because the flare operating limits did not apply during malfunction events. However, if flares are required to operate in a smokeless capacity during emergency releases, the commenters claimed that refineries would have to quadruple the number of flares at each refinery to control an event that may occur once every 2 to 5 years.

To support their suggestions, commenters pointed out that flaring during emergencies is the optimum way of handling very large releases and that the flare test data clearly demonstrate that visible emissions and/or high flare tip velocity do not suggest poor destruction efficiency during such events. The commenters also argued that operators should not have conflicting safety and environmental considerations to deal with during these times. The commenters stated that refiners are still subject to a civil suit even if the EPA uses its enforcement discretion where such a release would violate the limit and in order to avoid such liability, many new flares would have to be built. Commenters estimated that 500 new large flare systems at a capital cost in excess of $10–20 billion would need to be built because of the amount of smokeless design capacity that would be needed and that this significant investment would take the industry at least a decade to install.

Response: At the time of the proposed rule, we did not have any information indicating that flares were commonly operated during emergency releases at exit velocities greater than 400 ft/sec (which is 270 miles per hour (mph)). Similarly, we did not have information to indicate that flares were commonly designed to have a smokeless capacity that is only 20 to 30-percent of their ''hydraulic load capacity.'' While we are uncertain that refineries actually would install additional flares to the degree the commenters claim, based on the possibility that there may be an event every 2 to 5 years that would result in a deviation of the smokeless limit, we also recognize that it would be environmentally detrimental to operate hundreds of flares on hot standby in an effort to never have any releases to a flare that exceed the smokeless capacity of that flare. This is because operating hundreds of new flares to prevent smoking during these rare events will generate more ongoing emissions from idling flares than the no visible emissions limit might prevent during one of these events. Therefore, we considered alternative operating limits or alternative standards that could apply during these emergency release events.

As an alternative to the proposed requirement that flares meet the visible emissions and velocity limits at all times, we considered a work practice standard for the limited times when the flow to the flare exceeds the smokeless capacity of the flare. Owners or operators of flares would establish the smokeless capacity of the flare based on design specification of the flare. Below this smokeless capacity, the velocity and visible emissions standards would apply as proposed. Above the smokeless capacity, flares would be required to perform root cause analysis and take corrective action to prevent the recurrence of a similarly caused event. Multiple events from the same flare in a given time period would be a deviation of the work practice standard. *Force majeure* events would not be included in the event count for this requirement.

Based on industry claims that there is a hydraulic load flaring event, on average, every 4.4 years, we assumed the best performers would have no more than one event every 6 years, or a probability of 16.7-percent of having an event in any given year. We found that, over a long period of time such as 20 years, half of these best performers would have 2 events in a 3 year period, which would still result in over half the ''best performing'' flares having a deviation of the work practice standard if it was limited to 2 events in 3 years. Conversely, only 6 percent would have 3 events in 3 years over this same time horizon. Based on this analysis, 3 events in 3 years would appear to be ''achievable'' for the average of the best performing flares.

Pursuant to CAA section 112(d)(2) and (3), we are finalizing a work practice standard for flares that is based on the best practices of the industry, and considers the rare hydraulic load events that inevitably occur at even the best performing facilities.

The best performing facilities have flare management plans that include measures to minimize flaring during events that may cause a significant release of material to a flare. Therefore, we are requiring owners or operators of affected flares to develop a flare management plan specifically to identify procedures that will be followed to limit discharges to the flare as a result of process upsets or malfunctions that cause the flare to exceed its smokeless capacity. We are specifically requiring refinery owners or operators to implement appropriate prevention measures applicable to these emergency flaring events (similar to the prevention measures we are requiring in this final rule to minimize the likelihood of a PRD release). Refiners will be required to develop a flare minimization plan that describes these proactive measures and reports smokeless capacity. Refiners will need to conduct a specific root cause analysis and take corrective action for any flare event above smokeless design capacity that also exceeds the velocity and/or visible emissions limit. If the root cause analysis indicates that the exceedance is caused by operator error or poor maintenance, the exceedance is a deviation from the work practice standard. A second event within a rolling 3-year period from the same root cause on the same equipment is a deviation from the standard. Events caused by *force majeure,* which is defined in this subpart, would be excluded from a determination of whether there has been a second event. Finally, and again excluding *force majeure* events, a third opacity or velocity limit exceedance occurring from the same flare in a rolling 3-year period is a deviation of the work practice standard, regardless of the cause.

Comment: Several commenters suggested that the EPA should revise the combustion efficiency requirements to apply only to steam-assisted flares used as Refinery MACT control devices during periods of time that the flares are controlling Refinery MACT regulated streams. One commenter suggested that the EPA misused the TCEQ data in proposing the NHV_{cz} metric and that the proposed limits are overly conservative. The commenter requested that the EPA work with stakeholders to conduct additional testing to determine what, if any, operating parameters are appropriate and necessary to achieve an adequate destruction efficiency for non-steam-assisted flares.

Response: We disagree with the commenters that the combustion efficiency requirements should apply only to steam-assisted flares. The available data (for runs where steam assist is turned off) as well as the available combustion theories suggest that the combustion zone net heating value minimum limit, which is the vent gas net heating value for unassisted or perimeter air-assisted flares, is necessary to ensure proper flare performance. While we agree that additional data on air-assisted flares would allow for a more robust analysis, the data we do have strongly indicate that air-assisted flares can be over-assisted and that the combustion efficiency of air-assisted flares that are over-assisted is below 98-percent control efficiency.

Comment: A few commenters suggested that the proposed flare regulations should not apply to part 63, subpart R (gasoline loading) and subpart Y (marine vessel loading) facilities, and to part 61, subpart FF (benzene waste) facilities. The commenters recommended that flares associated with gasoline loading, marine vessel loading and wastewater treatment emissions need to comply only with the General Provisions for flares. Some of these commenters argued that these sources are more consistent in flow and composition than other refinery sources, so the new requirements are not necessary to ensure good combustion for these ‘‘dedicated’’ flares. Some commenters suggested that operators of flares with consistent flow and composition be allowed to use process knowledge or engineering judgment rather than be required to install continuous monitors or be subject to ongoing grab sampling requirements.

Some commenters noted that the required control efficiency for some refinery emissions sources subject to subpart CC sources is 95-percent. One commenter also requested that the EPA provide overlap provisions so flares used to control sources from different MACT sources would not have duplicative requirements.

Response: The regulatory revisions that we are finalizing apply to petroleum refinery sources subject to part 63, subparts CC and UUU. Gasoline loading, marine vessel loading and wastewater treatment operations that are part of the refinery affected source as defined at 40 CFR 63.640 are subject to subpart CC. Gasoline loading, marine vessel loading and wastewater treatment operations located at non-refinery source categories are not subject to part 63, subpart CC and, thus, would not be subject to the revisions to subpart CC being finalized in this action. To the extent that the commenters are requesting that the EPA establish flare requirements that would apply to flares that are not part of the refinery affected source, that request is beyond the scope of this rulemaking, which only addresses revisions to Refinery MACT 1 and 2. When we issue rules addressing requirements for other sources with flares, we will consider issues similar to those we considered in this action and determine at that time whether revisions to those other flare requirements are necessary.

The commenters note that some subpart CC emissions sources have only a control efficiency requirement of 95-percent. While this may be true, where the owner or operator chooses to control these sources through the use of a flare, operation of that flare was subject to operational requirements in the General Provisions at 40 CFR 63.11 and the best performing flares were achieving 98-percent control at the time the General Provisions were promulgated. At the time the General Provisions were promulgated, we received no comments that the EPA should set different operational limits for flares that are controlling emissions from sources where the standard may vary by level of control efficiency and we see no basis to do so now. The purpose of the revisions to the flare operating requirements is to ensure that flares are operating consistent with the MACT floor requirements for any and all sources that may use flares as a control device (79 FR 36905, June 30, 2014). As the MACT floor control requirements of certain refinery sources that allow the use of a flare as a control device is 98-percent, we established operational limits to ensure flares used as control devices meet this MACT requirement.

To the extent that the commenters are requesting that the EPA establish an alternative monitoring approach for flares in dedicated service that have consistent composition and flow, we agree that these types of flares, which have limited flare vent gas streams, do not need to have the same type of on-going monitoring requirements as those with more variable waste streams. Thus, we are establishing an option that refinery owners or operators can use to demonstrate compliance with the operating requirements for flares that are in dedicated service to a specific emission source, such as a wastewater treatment operation. Refinery owners or operators will need to submit an application for the use of this alternative. The application must include a description of the system, characterization of the vent gases that could be routed to the flare based on a minimum of 7 grab samples (14 daily grab samples for continuously operated flares) and specification of the net heating value that will be used for all flaring events (based on the minimum net heating value of the grab samples). We are also allowing engineering estimates to characterize the amount of gas flared and the amount of assist gas introduced into the system. For example, the use of fan curves to estimate air assist rates is acceptable. Flare owners or operators would use the net heating value determined from the initial sampling phase and measured or estimated flare vent gas and assist gas flow rates, if applicable, to demonstrate compliance with the standards.

Comment: A few commenters suggested that the EPA's proposed work practice and monitoring standards for flares are CAA section 112(d) ''developments'' required by law and supported by the evidence, and reflect best practices at many refineries today. One commenter suggested that the EPA must allow companies with consent decrees to meet their consent decree requirements as an alternative compliance approach and in lieu of the proposed requirements.

Response: We proposed the enhanced monitoring requirements and operating limits under authority of CAA sections 112(d)(2) and (d)(3) to ensure that flares used to control regulated Refinery MACT 1 or 2 gas streams are meeting the prescribed control efficiencies established at the time the MACT standard was promulgated. And, we continue to believe that these revisions are appropriate under CAA sections 112(d)(2) and (d)(3). The commenter has not suggested, and we do not believe, that the revisions promulgated would differ in substance if they were instead promulgated under CAA section 112(d)(6).

In general, we expect that the NHV_{cz} monitoring requirements that we are finalizing for flares will be consistent with the requirements in various consent decrees. However, we have not conducted a rigorous evaluation of equivalency between various requirements and therefore we are not at this time providing an allowance for flare owners or operators to comply with the NHV_{cz} operating limits and any provisions for necessary monitoring needed in the consent decree in lieu of the NHV_{cz} limits and monitoring requirements established in this rule. In the event that an owner or operator wishes to continue complying only with the requirements of a consent decree, the rule contains provisions by which owner or operator can seek approval for alternative limits that are at least equivalent to the performance achieved from complying with the operating limits included in the final rule.

iii. Pressure Relief Devices

Comment: Several commenters suggested that the EPA develop a work practice approach for atmospheric PRD rather than a prohibition on releases. One commenter recommended that the EPA establish a work practice standard for atmospheric PRDs that requires refiners to implement a base level of preventative measures including: Basic process controls, instrumented alarms, documented and verified routine inspection and maintenance programs, safety-instrumented systems, disposal systems, provide redundant equipment, increase vessel design pressure and systems that reduce fire exposure on equipment. Additionally, the commenter recommended that the EPA require refiners to perform root cause analysis and implement corrective action in the event of a release. The commenter stated these requirements would be similar to the root cause analysis/corrective action requirements recently promulgated for flares under NSPS subpart Ja and provided specific regulatory language for a proposed work practice approach. (See section 2.4.1.8 in Docket item EPA–HQ–OAR–2010–0682–0583.) One commenter requested that the EPA allow a process for companies to submit an application for case-by-case limits to be approved by the agency, either the EPA or a delegated state similar to the alternate NO_X limits for process heaters provided in NSPS subpart Ja. This commenter recommended that the EPA establish reasonable work practice standards, specifically suggesting that the EPA develop work practice standards consistent with API 521. The commenter stated that the EPA should provide an implementation period for compliance that goes beyond the timeframe provided under CAA section 112(d). The commenter added that the EPA should adopt specified changes to the definition of an atmospheric pressure relief safety valve and provided suggested regulatory language for a proposed work practice standard for PRDs in EPA–HQ–OAR–2010–0682–0549.

Another commenter stated that the EPA should require, as the Bay Area Air Quality Management District (BAAQMD) does, that any refinery that has a reportable PRD event must take certain steps to prevent such releases in the future (BAAQMD Rule 8–28–304). In particular, such a refinery must create a Process Hazard Analysis, meet the Prevention Measures Procedures specified in section 8–28–405, and conduct a failure analysis of the incident, to prevent recurrence of similar incidents (Id. Reg. section 8–28–304.1). If a second release occurs, then, within one year, the facility must vent its PRDs to a vapor recovery or disposal system that meets certain requirements (Id. Reg. section 8–28–304.2). The commenter asserted that the EPA's prohibition on releases to the atmosphere from PRD will ensure that refineries take the necessary steps to prevent such releases, or install control devices so that any releases from PRDs that must occur are vented through a control device to reduce the amount of toxic air pollution they emit. At a minimum, the commenter stated, the EPA must prohibit these uncontrolled emissions and require monitoring and reporting to assure compliance and ensure that the emission standards apply at all times, as required by the Act. The commenter argued that the EPA must also, however, consider requiring the additional developments that have been put into place in the BAAQMD and also require control devices to be used for all PRD, as some local air districts require. In addition, the commenter supported the EPA's monitoring and reporting requirements for PRD releases and the proposed electronic reporting requirements, which the EPA recognized are needed to assure compliance and assist with future rulemakings and as that provision requires, the EPA also must make all information reported publicly available online promptly and in an accessible and understandable format.

Response: We agree that, under the proposal, refineries would consider installing add-on controls to comply with the prohibition on atmospheric releases from PRDs. In addition, they would consider venting these control devices to existing control devices, including flares. However, it may not be feasible to vent some or all of the PRDs to existing flares if the flares are near their hydraulic load capacity based on the processes already connected to the flares. Flares have negative secondary impacts when operated at idle conditions for the vast majority of time, which could be the case if they were installed solely to address PRD releases. These secondary impacts result from GHG, CO and NO_X emissions. Some PRDs may vent materials that are not compatible with flare control and would need to be vented to other controls.

To estimate the impact of the proposed prohibition on venting PRDs to the atmosphere, we estimated that at least one new flare per facility would be required to handle releases from PRDs, based on the number of atmospheric PRDs reported at refineries; that 60-percent of the PRDs could be piped to existing controls at minimal costs and the other 40-percent would have to be piped to new flares; and that, on average, each new flare would service 40 PRDs. Based on these assumptions, 151 new flares would be needed or approximately one new flare per refinery. At a capital cost of $2 million for each new flare, which would not include long pipe runs, if needed, to PRD that are dispersed across the plant, we estimate that the capital cost of the prohibition on venting to the atmosphere would exceed $300 million. Considering the fuel needed (approximately 50,000 scf/day per flare) and a natural gas price of $4.50 per 1,000 scf, we estimate the annual operating cost for these new flares to be $12 million.

PRDs are unique in that they are designed for the purpose of releasing or ''popping'' as a safety measure to address pressure build-up in various systems—pipes, tanks, reactors—at a facility. These pressure build-ups are typically a sign of a malfunction of the underlying equipment. While it would be difficult to regulate most malfunction events because they are unpredictable and can vary widely, in the case of PRDs, they are equipment installed specifically to release during malfunctions and as such, we have information on PRDs in our 2011 Refinery ICR and through the SCAAMD and BAAQ rules to establish standards for them. After reviewing these comments, we thus examined whether it would be feasible to regulate these devices under CAA section 112(d)(2) and (3).

After reviewing the comments, we agree with the commenters who suggest that the BAAQMD rule, as well as a similar South Coast Air Quality Management District (SCAQMD) rule that address PRD releases (SCAQMD Rule 1173), provide work practice standards that reflect the level of control that applies to the best performers. Consequently, we developed a work practice standard for PRD based on a detailed MACT analysis considering the requirements in these rules. Our rationale for the selected MACT requirements is provided in section IV.C.4 of this preamble. The work practice standards that we are finalizing for PRDs require refiners to establish proactive measures for each affected PRD to prevent direct release of HAP to the atmosphere as a result of pressure release events. In the event of an atmospheric release, we are requiring refinery owners or operators to conduct root cause analysis to determine the cause of a PRD release event. If the root cause was due to operator error or negligence, then the release would be a deviation of the standard. For any other release (not including those caused by force majeure events), the owner or operator would have to implement corrective action. A second release due to the same root cause for the same equipment in a 3-year period would be a deviation of the work practice standard. Finally, a third release in a 3-year period would be a deviation of the work practice standard, regardless of the root cause. *Force majeure* events would not count in determining whether there has been a second or third event.

With respect to defining ''atmospheric pressure relief safety valve'' as suggested by the commenter, we note that the June 30, 2014, proposed amendments in 40 CFR 63.648(j) used the term ''relief valve'' because this was a defined term in Refinery MACT 1. However, the proposed amendments included clauses such as ''if the relief valve does not consist of or include a rupture disk.'' Thus, we specifically intended to apply the pressure relief management requirements broadly to ''pressure relief devices'' and not just ''valves.'' To clarify this, we have revised the regulatory language to use the term ''pressure relief device'' rather than ''relief valve'' to clearly include rupture disks or similar types of equipment that may be used for pressure relief.

4. What is the rationale for our final approach and final decisions for the revisions pursuant to CAA section 112(d)(2) and (3)?

We revised the MACT floor determination for DCU sources. CAA section 112(d)(3)(A) requires the MACT floor for existing sources to exclude ''. . . those sources that have, within 18 months before the emission standard is proposed or within 30 months before such standard is promulgated, whichever is later, first achieved a level of emission rate or emission reduction which complies, or would comply if the source is not subject to such standard, with the lowest achievable emission rate (as defined by section 171) applicable to the source category and prevailing at the time, in the category or subcategory for categories and subcategories with 30 or more sources.'' Because we have determined that a 2 psig emissions limitation is equivalent with a LAER emission limit for DCU, we revised the MACT floor analysis in order to exclude sources that first met the 2 psig limit on or after December 30, 2012. For existing sources, based on the revised MACT analysis, we concluded that the MACT floor is still 2 psig. However, because the information on which we relied was submitted in response to the 2011 Petroleum Refinery ICR which requested ''typical'' venting pressures and because providing an allowance to average across venting periods does not reduce the emissions reductions achieved, we are providing a 60-event averaging period for existing sources in response to public comments received.

For new DCU sources, our revised analysis identified one DCU subject to permit emission limitations of 2.0 psig pressure limit prior to venting on a per event basis. Under CAA section 112(d)(3), the MACT standard for new sources cannot be less stringent than the emission control achieved in practice by the best-controlled similar source. Thus, we are finalizing a limit of 2.0 for new DCU sources. We note that as 2.0 psig limit is more stringent than a 2 psig limit because of the rounding convention of rounding to the number of significant digits for which the standard is expressed. For example, a 2.4 psig venting pressure is compliant with a 2 psig limit, while it is not compliant with a 2.0 psig limit.

We evaluated the costs of requiring existing sources to meet a 2.0 psig limit as a beyond-the-MACT-floor option. We determined the incremental cost of going from a 2 psig limit with an allowance to average over 60 events to a 2.0 psig limit on a per event basis was approximately $70,000 per ton of HAP reduced considering VOC credits. Based on this high incremental cost-effectiveness, we concluded that the MACT floor requirement for existing DCU sources was MACT. As discussed in detail in the proposal, we do not consider it technically feasible to meet a 1 psig pressure limit (effectively a 1.4 psig limit) on a not-to-be-exceeded basis. Thus, we rejected this beyond the floor control option for both existing and new DCU sources. See the memorandum titled ''Reanalysis of MACT for Delayed Coking Unit Decoking Operations'' in Docket ID No. EPA–HQ–OAR–2010–0682 for additional details regarding our re-analysis of MACT for DCU decoking operations.

In response to comments received on the prohibition of draining prior to achieving the proposed pressure limit (see Section 7.2.1 in the ''National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries—Background Information for Final Amendments: Summary of Public Comments and Responses'' in Docket ID No. EPA–HQ–OAR–2010–0682), we are providing specific provisions to allow for draining under special conditions. The specific provision and our rationale for providing them are provided below.

First, we learned that certain DCU are designed to completely fill the drum with water and allow the water to overflow in the overhead line and drain to a receiving tank in order to more effectively cool the coke bed. Owners or operators of this DCU design were concerned that the water overflow may be considered a drain and also stated that overhead temperature rather than pressure would be a better indicator of effective bed cooling. In reviewing this type of DCU design, we find that this design has some unique advantages to traditional DCU to effect better cooling of the coke drum, and therefore we do not want to preclude its use. Based on saturated steam properties, we determined that an overhead temperature of 220 °F would achieve equivalent or greater emissions reductions than a 2 psig pressure limitation and an overhead temperature of 218 °F would achieve equivalent or greater emissions reductions than a 2.0 psig pressure limitation. Therefore, we are including these temperature limits as alternatives to the 2 or 2.0 psig pressure limitations for existing and new DCU affected sources, respectively. With respect to the overflow ''drain,'' we remain concerned with emissions from draining superheated water. However, if submerged fill is used in the atmospheric tank receiving the overflow water, the superheated water will be cooled by the water within the tank and emissions that occur during the conventional draining of water (from the flashing of superheated water into steam) can be prevented. Therefore, we are allowing the use of water overflow provided the overflow ''drain'' water is hard-piped to the receiving tank via a submerged fill pipe (pipe below the existing liquid level) whenever the overflow water exceeds 220 °F.

Second, we received comments that, for conventional DCU (those not designed to allow water overflow), there is a limit to the maximum water level in the drum, which limits to some extent how much cooling water can be added to the coke drum. In rare cases, the coke drum does not cool sufficiently using the typical cooling steps. In this case, the common industry practice is to partially drain the coke drum and refill it with additional cooling water. This ''double-quench'' process is needed for safety reasons to sufficiently cool the coke drum contents prior to the decoking operations. Therefore, commenters requested provisions to allow double-quenching of the coke drum. We recognize the safety issues associated with coke blow-out during coke cutting if there is a portion of the coke bed that is not sufficiently cooled and we agree that double-quenching is an effective means to cool the coke drum in those rare instances that the typical cooling cycle does not sufficiently cool the coke drum contents, so we considered granting the commenters' request. As noted previously, the primary concern with early draining of the coke drum is the emissions that are expected to occur as a result of draining superheated water. We recognize, however, that the water temperature near the bottom of the coke drum is typically much lower than at the top of the coke drum. If the temperature of the water drained from the bottom of the coke drum remains below 210 °F, this would minimize steam flashing and associated HAP emissions since the water drained would not be superheated. We conclude that the use of double quenching is appropriate for cases when the coke drum is not sufficiently cooled using the normal cooling procedures provided the temperature of the water drained remains below 210 °F, and it is consistent with the practices of the best performing sources. Consequently, we are finalizing provisions to allow the use of double-quenching for DCU provided the temperature of the water drained remains below 210 °F.

For the CRU, we are finalizing the proposed revisions to require CRU that employ active purging to meet the MACT emissions limitations in Tables 15 and 16 in subpart UUU at all times regardless of vessel pressure. We received limited comments regarding our proposal; these comments generally concerned the costs associated with the proposed emissions limitations. As discussed in our proposal, and based on data submitted in response to the ICR, emissions using active purging are much higher than those not using active purging. In the original rule, we based the MACT floor on the best performing facilities that used sequential pressurizations and depressurizations rather than active purging. Thus, in the proposal, we concluded that allowing owners or operators to actively purge while at low pressures was inconsistent with the MACT floor emissions limitations achieved by the best performing 12-percent of sources when the MACT floor was originally established. As we are simply requiring these facilities to meet the same emission levels determined to be MACT, we do not consider costs of potential additional controls to be a viable rationale to allow these units to emit several times more HAP than the units upon which the MACT requirements were based and the emissions levels achieved in practice by the vast majority of other CRU sources.

For flares, we are finalizing proposed revisions to include detailed flare monitoring and operating requirements. We are including the flaring provisions for refineries in the Refinery MACT rules and removing the cross-references to the flaring requirements in the General Provisions. The final regulatory requirements differ from the proposed requirements in several respects. First, we are not finalizing the ban on halogenated vent streams because we did not include sufficient justification or include cost estimates for this proposed provision and we did not include any monitoring requirements to ensure compliance with this ban on halogenated vent streams.

We are finalizing the proposed no visible emissions limit and the flare tip velocity limit but they will apply only when the flare vent gas flow rate is below the smokeless capacity of the flare. We received a number of comments stating that the no visible emissions limit and the flare tip velocity limit cannot be met during large malfunctions and emergency shutdown events. In response to comments, we are finalizing work practice standards for emergency flaring events using the proposed no visible emission limit and flare tip velocity limit as thresholds in the final rule to trigger root cause analysis when the flare vent gas flow rate is above the smokeless capacity of the flare. The final work practice standard includes requirements to develop a flare management plan, to implement prevention measures, and to perform root cause analysis and implement corrective action following each flaring event that exceeds the smokeless capacity of the flare. There is also a limit on the number of these flaring events that a given flare may have in the 3-year period. We are establishing these provisions because we now recognize that flares have two different design capacities: A smokeless design capacity and a hydraulic load capacity. We determined that the proposed visible emissions limit and the flare tip velocity limit for very large flow events are not the MACT floor for such events. The final work practice standards for flaring events are based on the best performing facilities and will result in emission reductions in a technically feasible manner without any negative secondary impacts.

We consider it appropriate to establish a work practice standard for flares as provided in CAA section 112(h). While it is possible to monitor gaseous streams going into the flare (as we have required for the flare operating requirements) it is not possible to design and construct a conveyance to capture the emissions from a flare. While knowledge of the composition and flow of gases entering the flare provides a reasonable basis for establishing operating requirements for normal operations, we have no data on flare performance under conditions in the hydraulic load range. While smoke in the flare exhaust is an indication of incomplete combustion, it is uncertain how much deterioration of HAP destruction efficiency occurs during a smoking event. We also consider that the application of a measurement methodology for flare exhaust is not practicable due to technological and economic limitations. Passive FTIR has been used to determine combustion efficiency in flare exhaust, but these are essentially manual tests, and the measurement accuracy is dependent on how well the monitor is aligned with the flare exhaust plume. Changes in wind direction require manual movement of the monitoring system. It is also unclear if these systems can accurately measure combustion efficiency during high smoking events. These systems also require very specialized expertise, and we consider that it is both technologically and economically infeasible to measure flare exhaust emissions, particularly during high load events. Consequently, for emergency flare releases, we conclude that it is appropriate to establish a work practice standard as provided in CAA section 112(h).

We also received comments that the daily visible emissions observations were burdensome and unnecessary and some commenters suggested that facilities be allowed to use video surveillance cameras. We concluded that video surveillance cameras would be at least as effective as the proposed daily 5-minute visible emissions observations using Method 22. We are finalizing the proposed visible emissions monitoring requirements Method 22 and the alternative of using video surveillance cameras.

We are simplifying the combustion zone gas property operating limits in response to public comments received. Specifically, we are finalizing requirements that all flares meet a minimum operating limit of 270 BTU/scf NHV_{cz} on a 15-minute average, and we are providing that refiners use a corrected heat content of 1,212 BTU/scf for hydrogen to demonstrate compliance with this operating limit. We determined that a corrected heat content of 1212 BTU/scf for hydrogen provided a better indication of flare performance than without the correction. We also determined that the other combustion zone parameters, which were primarily proposed to provide suitable methods for flares that had high hydrogen concentrations, were no longer necessary when a 1,212 Btu/scf net heating value is used for hydrogen. Therefore, we are not finalizing the alternative combustion zone operating limits based on lower flammability limit or combustibles concentration. We are also not finalizing separate combustion zone operating limits for gases meeting the proposed hydrogen-olefin interaction criteria. In our revised analysis of the data, we analyzed all of the data together and determined the 270 Btu/scf NHV_{cz} operating limit provided in the final rule would adequately ensure that flares achieve the desired 98-percent control efficiency regardless of the composition of gas sent to the flare.

For air-assisted flares, we are finalizing the additional ''dilution parameter'' operating limit only for the net heating value dilution parameter, NHV_{dil}. Similar to the requirements we are finalizing for the combustion zone parameters, we are finalizing requirements that flares meet a minimum operating limit of 22 BTU/ft^2 NHV_{dil} on a 15-minute average, and we are providing that refiners use a corrected heat content of 1,212 BTU/scf for hydrogen to demonstrate compliance with this operating limit. For the reasons explained above, we are not finalizing the proposed alternative dilution parameter operating limits based on lower flammability limit or combustibles concentration, and we are not finalizing separate dilution parameter operating limits for gases meeting the proposed hydrogen-olefin interaction criteria.

For flares in dedicated service, we are establishing an alternative to continuous or on-going grab sample requirements for determining waste gas net heating content to reduce the burden of sampling for flare waste gases that have consistent compositions. Flares in dedicated service can use initial sampling period and process knowledge to determine a fixed net heating value of the flare vent gas to be used in the calculations of NHV_{cz} and, if applicable, NHV_{dil}.

We are revising the definition of MPV to remove the exemption for in situ sampling systems for the reasons provided in the proposed rule.

We received comments recommending that a work practice standard be adopted for PRD rather than the proposed prohibition of atmospheric PRD releases. Commenters stated that the prohibition was infeasible due to the proposed immediate timing of the requirement and impractical due to cost considerations. After reviewing these comments as well as the BAAQMD rule (Regulation 8, Rule 8–28–304) and the SCAQMD rule (Rule 1173), we have determined that the work practice standards in these rules reflect the level of control that applies to the best performers. Therefore, we proceeded to evaluate appropriate MACT requirements based on the provisions in these rules.

The BAAQMD rule requires sources to implement a minimum of three prevention measures to limit the possibility of a release. The BAAQMD uses a ''release event'' threshold of 10 lbs/day of organic or inorganic pollutants; the SCAQMD rule effectively uses a release event threshold of 500 lbs VOC/day. When a release event occurs, both rules require that the refiner perform a root cause analysis and take corrective action (including additional prevention measures). In addition, both rules require piping the PRD to a flare if there are more than two release events (releases above a certain release size threshold) in a 5-year period. Both rules include a number of exemptions for certain types of PRD that are not expected to release significant amounts of pollutants to the air or that are not feasible to control because of pressure considerations. These include PRD associated with storage tanks, vacuum systems and equipment in heavy liquid service as well as liquid thermal relief valves that are vented to process drains.

There are five refineries subject to the BAAQMD rule and seven refineries subject to the SCAQMD rule, accounting for 8-percent of refineries nationwide and representing the industry's best performers. We consider the BAAQMD rule to be the more stringent of the two because this rule requires sources to implement a minimum of three prevention measures to limit the possibility of a release (the SCAQMD rule has no similar requirement) and uses a lower mass threshold for what is considered a ''release event'' (10 lbs/day of organic or inorganic pollutants versus the 500 lbs VOC release threshold in the SCAQMD rule). Therefore, the BAAQMD rule is considered to be the MACT floor requirement for PRDs associated with new affected sources and the SCAQMD rule is considered to be the MACT floor for PRDs associated with existing affected sources.

In general, an open PRD is essentially the same as a miscellaneous process vent that is vented directly to the atmosphere. Consistent with our treatment of miscellaneous process vents and consistent with the two California rules, we believe that it is appropriate to exclude certain types of PRD that have very low potential to emit based on their type of service, size and/or pressure. For example, PRD that have a potential to emit less than 72 pounds per day of VOC, considering the size of the valve opening, design release pressure, and equipment contents, would be considered in a similar manner as Group 2 miscellaneous process vents and would not require additional control. The two California rule requirements do not apply to PRD on storage tanks and vacuum systems. Most of these PRD have a design release pressure of 2.5 psig and thus have a very limited potential to emit. It is technically infeasible to pipe these sources to a flare (or other similar control system) because the back pressure in the flare header system generally exceeds 2.5 psig. We note that some storage tanks can operate at elevated pressure (*i.e.,* pressure tanks). Therefore, rather than follow exactly the requirements in the California rules, we determined it more practical to exclude PRD with design release pressure of less than 2.5 psig.

Any release from a PRD in heavy liquid service would have a visual indication of a leak and any repairs to the valve would have to be further inspected and, if necessary, repaired under the existing equipment leak provisions. Therefore, consistent with the BAAQMD rule, we are exempting PRD in heavy liquid service from the work practice standards we are establishing in this final rule.

Both the BAAQMD and SCAQMD rules exempt thermal expansion valves that are ''vented to process drains or back to the pipeline.'' We are unclear what is meant by ''vented to process drains''; however, if a liquid is released from a PRD via hard-piping to a drain system that meets the control requirements specified in Refinery MACT 1, we consider that these PRD are controlled and they would not be subject to the work practice standard established in this final rule. Similarly, all PRD in light liquid service that are hard-piped to a controlled drain system (or back to the process or pipeline) are otherwise subject to a MACT requirement and would not be subject to the work practice standard.

In considering thermal relief valves not vented to process drains or back to the pipeline, we expect that releases from these thermal relief valves will be small and generally under the release event thresholds specified in the California rules. Therefore, the work practice standards do not apply to PRD that are designed solely to release due to liquid thermal expansion.

The primary goal of the PRD work practice standard is to reduce the size and frequency of releases. The SCAQMD rule is targeted towards fairly large releases (compared to the direct PRD releases reported in response to the Refinery ICR), so it will reduce the frequency of large releases, but it does little to reduce the frequency of smaller releases. To more effectively reduce the size and frequency of all releases, we consider it important to require the implementation of prevention measures (as required in the BAAQMD rule) and require root cause analysis and corrective action for PRD releases from all PRD subject to the work practice standard. While we recognize that if a PRD opens for a short period of time, the release might be below the release thresholds in the SCAQMD rules, we believe the release may be indicative of an important issue or design flaw. Because the potential for large emissions exist from the PRD subject to the work practice standard, we think it is reasonable to require a root cause analysis be conducted and appropriate corrective action implemented to potentially identify this issue and prevent a second release which, if the issue remains uncorrected, could be significant.

Requiring that prevention measures be implemented on all PRD subject to the work practice standard and not establishing a release threshold for release events is a variation from the SCAQMD rule. However, we also considered the allowable release frequency. We believe that our adoption of this approach is balanced by our not adopting the SCAQMD provisions requiring that PRD be vented to a flare or other control system or that refiners pay a fee if there are multiple releases of a certain size within a specified timeframe.[12] In place of this system, we are limiting the number of events from each PRD that can occur in a 3 year time period (2, if root causes are different), and in place of a fine, or routing to control, stating that the 3rd release in 3 years for any root cause is a deviation of the standard.

Because we are not including a size threshold for release events as in the SCAQMD rule, it is natural to assume release events would occur more frequently than release events subject to the SCAQMD rules. Also, based on our Monte Carlo analysis of random rare events, we note that it is quite likely to have two or three events in a 5-year period when a long time horizon (*e.g.,* 20 years) is considered. Therefore, considering our analysis of emergency flaring events and the lack of a 500 lb/day release threshold, we considered it reasonable to use a 3-year period rather than a 5-year period as the basis of a deviation of the work practice standard.

The SCAQMD work practice standards do not apply to releases that are demonstrated to ''result from natural disasters, acts of war or terrorism, or external power curtailment beyond the refinery's control, excluding power curtailment due to an interruptible service agreement.'' These types of events, which we are referring to as ''*force majeure*'' events, are beyond the control of the refinery owner or operator. We are providing that these events should not be included in the event count, but that they would be subject to the root cause analysis in order to confirm whether the release was caused by a *force majeure* event.

Consistent with the requirements in the SCAQMD rule, we are requiring refinery owners or operators to conduct a root cause analysis for a PRD release event. If the root cause was due to operator error or negligence, then the release would be a deviation of the standard. For any other release (not including those caused by *force majeure* events), the owner or operator would have to implement corrective action. We consider that a second release due to the same root cause for the same equipment in a 3-year period would be a deviation of the work practice standard. This provision will help ensure that root cause/corrective action are conducted effectively. Finally, a third release in a 3-year period (not including those caused by *force majeure* events) would be a deviation of the work practice standard, regardless of the root cause. While we are using a 3-year interval rather than the 5-year interval provided in the SCAQMD, we consider that the requirements as included in this final rule (*i.e.,* the inclusion of prevention measure requirements and no thresholds for release events) will achieve equivalent if not greater emissions reductions than the SCAQMD rule. We also consider that, given the prevention measure requirements and a 3-year period, there is less likelihood of unusual random events that happen over a short period of time that may cause refinery owners or operators to feel compelled to vent the PRD to a flare to eliminate concerns regarding potential non-compliance. Thus, we project that the requirements that we have included in the final rule will achieve emissions reductions commensurate to or exceeding the requirements in the SCAQMD rule (that serves as the MACT floor for existing sources) but will achieve those

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[12] The SCAQMD rule requires PRD to be vented to a flare or other control device if there is a single release in excess of 2,000 pounds of VOC in a 24-hour period or three releases in excess of 500 pounds of VOC in a 5-year period or, alternatively, pay a $350,000 fee. Thus, the SCAQMD rule would allow, for example, two releases of over 500 pounds of VOC each within a 5-year period without any penalty provided a third event did not occur. If a third event did occur, the refinery owner or operator would then have to vent the PRD to a flare or other control system or pay a fee ($350,000) for the third release over 500 pounds of VOC.

reductions in a more cost-effective manner.

We also considered requiring all PRD to be vented through a closed vent system to a control device as an alternative beyond-the-MACT floor requirement. While this requirement would provide additional emission reductions beyond those we are establishing as the MACT floor, these reduction come at significant costs. Capital costs for requiring control of all atmospheric PRD is estimated to be approximately $300 million compared to $11 million for the requirements described above. The total annualized cost for requiring control of all atmospheric PRD is estimated to be approximately $41 million/year compared to $3.3 million/year for the requirements described above. We estimate that the incremental cost-effectiveness of requiring control of all atmospheric PRD compared to the requirements described above exceeds $1 million per ton of HAP reduced. Consequently, we conclude that this is not a cost-effective option for existing sources.

The final requirements that we have developed for PRD achieve equal or greater emission reductions than those achieved by the SCAQMD rule (MACT floor). To the extent those requirements are more stringent that the SCAQMD, they are cost-effective. We could not identify an alternative requirement that provided further emission reductions in a cost-effective manner. Thus, we conclude that the work practice standards described above represent MACT for existing sources.

The BAAQMD rule, which represents the requirements applicable to the best performing sources, is the basis for new source MACT for PRD. Based on the specific provisions for PRD in the BAAQMD rule, we conclude that the MACT floor requirement is to have all PRD in HAP service associated with a new affected source vented through a closed vent system to a control device. As with existing sources, the PRD WPS would also contain the same exclusions (*e.g.,* heavy liquid service PRDs, thermal expansion valves, liquid PRDs that are hard-piped to controlled drains, PRD with release pressures of less than 2.5 psig, PRD with emission potential of less than 72 lbs/day, and PRD on mobile equipment). These provisions are similar to the applicability provisions of the BAAQMD rule. Thus, we retain the same applicability of the work practice standard for PRDs on new or existing equipment, but all affected PRD on a new source would be required to be controlled. This is essentially equivalent to the proposed requirement of no atmospheric releases. We could not identify a control option more stringent than the BAAQMD rule as applied to new sources. Therefore, we conclude that venting all PRD in HAP service through a closed vent system to a flare or similar control system is MACT for PRD associated with new affected sources.

We consider it appropriate to establish a work practice standard for PRD as provided in CAA section 112(h). While it may be possible to design and construct a conveyance for PRD releases, we consider that the application of a measurement methodology for PRDs is not practicable due to technological and economic limitations. First, it is not practicable to use a measurement methodology for PRD releases. The venting time can be very short and may vary widely in composition and flow rate. The often-short duration of an event makes it infeasible to collect a grab sample of the gases when a release occurs, and a single grab sample would not account for potential variation in vent gas composition. It would be economically prohibitive to construct an appropriate conveyance and install and operate continuous monitoring systems for each individual PRD in order to attempt to quantitatively measure a release event that may occur only a few times in a 3-year period. Additionally, we have not identified an available, technically feasible continuous emission monitoring systems that can determine a mass VOC or HAP release quantity accurately given the flow, composition and composition variability of potential PRD releases from refineries. Consequently, we conclude that it is appropriate to establish a work practice standard for PRD releases as provided in CAA section 112(h).

D. NESHAP Amendments Addressing Emissions During Periods of SSM

1. What amendments did we propose to address emissions during periods of SSM?

We proposed to eliminate the SSM exemption in 40 CFR part 63, subparts CC and UUU. Consistent with *Sierra Club* v. *EPA*, we proposed standards in these rules that apply at all times. We also proposed several revisions to Table 6 of subpart CC of 40 CFR part 63 and to Table 44 to subpart UUU of 40 CFR part 63 (the General Provisions Applicability tables for each subpart), including eliminating the incorporation of the General Provisions' requirement that the source develop an SSM plan, and eliminating and revising certain recordkeeping and reporting requirements related to the SSM exemption.

For Refinery MACT 1, we proposed that the use of a bypass at any time to divert a Group 1 miscellaneous process vent to the atmosphere is a deviation of the emission standard, and specified that refiners install, maintain and operate a continuous parameter monitoring system (CPMS) for flow that is capable of recording the volume of gas that bypasses the APCD.

We also proposed to revise the definition of MPV to remove the exclusion for ''Episodic or non-routine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring and catalyst transfer operations.'' We also proposed that the control requirements for Group 1 MPV apply at all times, including startup and shutdowns.

For Refinery MACT 2, we proposed alternate standards for three emission sources for periods of startup or shutdown. We proposed PM standards for startup of FCCU controlled with an ESP under Refinery MACT 2 because of safety concerns associated with operating an ESP during an FCCU startup. For FCCU controlled by an ESP, we proposed a 30-percent opacity limit (on a 6-minute rolling average basis) during the period that torch oil is used during FCCU startup. For startup of FCCU without a post-combustion device under Refinery MACT 2, we proposed a CO standard based on an excess oxygen concentration of 1 volume percent (dry basis) based on a 1-hour average. For periods of SRU shutdown, we proposed to allow diverting the SRU purge gases to a flare meeting the design and operating requirements in 40 CFR 63.670 (or, for a limited transitional time period, 40 CFR 63.11) or to a thermal oxidizer operated at a minimum temperature of 1,200 °F and a minimum outlet oxygen concentration of 2 volume percent (dry basis). For other emission sources in Refinery MACT 2, we proposed that the requirements that apply during normal operations should apply during startup and shutdown.

2. How did the SSM provisions change since proposal?

a. Refinery MACT 1

We proposed that when process equipment is opened to the atmosphere (*e.g.,* for maintenance), the existing MPV emissions limits apply. In this final rule, we are instead finalizing startup and shutdown provisions that apply to these venting events. These startup and shutdown provisions are work practice standards that allow refinery owners or operators to open process equipment during startup and shutdown provided that the equipment is drained and purged to a closed system until the hydrocarbon content is less than or equal to 10-percent of the LEL. For those situations where 10-percent LEL cannot be demonstrated (no direct measurement location), the equipment may be opened and vented to the atmosphere if the pressure is less than or equal to 5 psig. Active purging of the equipment is only allowed after the 10-percent LEL level is achieved, regardless of the pressure of the equipment/vessel. We are establishing a separate requirement for very small process equipment, defined as equipment where it is physically impossible to release more than 72 lbs VOC per equipment opening based on the size and contents of the equipment. This definition is consistent with the Group 1 applicability cutoff for control of miscellaneous process vents. We also developed requirements specific to catalyst changeout activities where pyrophoric catalyst (*e.g.,* hydrotreater or hydrocracker catalysts) must be purged using recovered hydrogen. These provisions include: Documenting the procedures for equipment openings and procedures for verifying that events meet the specific conditions above using site procedures used to de-inventory equipment for safety purposes (*i.e.,* hot work or vessel entry procedures) and documenting any deviations from the work practice standard requirements.

b. Refinery MACT 2

We are expanding the proposed 1-percent minimum oxygen operating limit alternative for organic HAP to apply for all FCCU startup and shutdown events (rather than only partial burn FCCU with CO boilers during startup). We are replacing the proposed opacity limit alternative to the metal HAP standard with a minimum cyclone face velocity limit and we are extending that alternative limit to all FCCU (regardless of control device) for both startup and shutdown in this final rule.

We are extending the proposed alternative for SRU to monitor incinerator temperature and excess oxygen limits during SRU shutdowns to also apply during periods of startup.

3. What key comments did we receive on the SSM revisions and what are our responses?

a. Refinery MACT 1

Comment: Many commenters stated that the proposed extension of the MPV definition to episodic maintenance startup and shutdown vents and elimination of the SSM exception for storage tanks would create hundreds or thousands of new vents per refinery per year and generate massive on-going burdens. The commenters argued that the EPA has not included in the record any analysis of the potential environmental benefits, costs or operational and compliance feasibility and impacts associated with this requirement and that many of these requirements will result in delayed and extended equipment and process outages. One commenter asserted that the EPA has articulated no justification for applying emission standards to these events, nor any analysis consistent with CAA section 112 for a determination that MACT standards are appropriately applied to these emission events under the criteria in CAA section 112(d).

Many commenters stated that every time a vessel is opened for inspection or maintenance each vent point will have to be evaluated as a potential MPV or storage tank vent. If a particular vent point (*e.g.,* bleeder) used for maintenance, startup or shutdown handles material that is initially greater than 20 ppm HAP, then it is a MPV. If there is a potential to emit greater than or equal 72 lbs/day of VOC, then it is a Group 1 MPV and must be controlled. If there is a potential of less than 72 lb/day VOC release, then it is a Group 2 MPV and subject to recordkeeping requirements. Commenters stated that in a refinery there would be tens or more such activities per day associated with normal maintenance and inspection; during turnarounds, there could be hundreds of such MPVs. Commenters added that these MPVs may then need to be individually accounted for and permitted creating an unnecessary permitting and recordkeeping burden for these periodic emissions.

Commenters recommended a general set of work practice requirements for maintenance, startup and shutdown of vents, based on state requirements, that do not impose the permitting, notice and evaluation requirements associated with identifying these vents individually. Commenters explained that states have dealt with these episodic vents by establishing them as a special class of process vent with limited recordkeeping requirements and subject to a work practice standard, rather than the normal MPV requirements. A key element of these work practices is clear identification of the criteria for releasing these vents to the atmosphere and for routing these vents to control after hydrocarbon is reintroduced, which the commenters asserted the current rule does not provide. Commenters proposed that a work practice standard could include removing process liquids to the extent practical and depressuring smaller volume equipment until a pressure of <5 psig is achieved and/or purging and depressuring to a control device until the vent has a hydrocarbon concentration of less than 10-percent of the LEL. The commenters suggested that these standards should provide clear easily monitored criteria for when this equipment can be vented to the atmosphere, and should not impose the permitting, notice and evaluation requirements associated with identifying these vents as individual MPVs. One commenter provided draft regulatory language for a work practice requirement.

Response: We proposed to eliminate the episodic and non-routine emission exclusion in order to ensure that the MACT includes emission limits that apply at all times consistent with the holding in Sierra Club. At the time of the proposal, we expected that essentially all SSM event emissions would be routed to flares that are subject to the MACT standards and, thus, would serve to control these emissions. However, we recognize that maintenance activities that require equipment openings are a separate class of startup/shutdown emissions because there must be a point in time when the vessel can be opened and any emissions vented to the atmosphere. We acknowledge that it would require a significant effort to identify and characterize each of these potential release points for permitting purposes.

In considering these comments and whether we should establish a separate limit that would apply to these equipment openings, we reviewed state permit requirements and the practices employed by the best performing sources. We found that some state or local agencies required depressuring to 5 psig prior to atmospheric releases while others required the gases to have organic concentrations at or below 10-percent of LEL prior to atmospheric venting. In the final rule, we are establishing a requirement that prior to opening process equipment to the atmosphere, the equipment must first be drained and purged to a closed system so that the hydrocarbon content is less than or equal to 10-percent of the LEL. For those situations where 10-percent LEL cannot be demonstrated, the equipment may be opened and vented to the atmosphere if the pressure is less than or equal to 5 psig, provided there is no active purging of the equipment to the atmosphere until the LEL criterion is met. For equipment where it is not technically possible to depressurize to a control system, we allow venting to the atmosphere where there is no more than 72 lbs VOC per day potential, consistent with our Group 1 applicability cutoff for control of process vents. For catalyst changeout activities where hydrotreater pyrophoric catalyst must be purged we have provided limited allowances for direct venting. Provisions to demonstrate compliance with this work practice include documenting the procedures for equipment openings and procedures for verifying that events meet the specific conditions above using site procedures used to de-inventory equipment for safety purposes (*i.e.,* hot work or vessel entry procedures).

b. Refinery MACT 2

Comment: Several commenters noted that there was a proposed specific alternative metal HAP/PM standard for startup of an FCCU controlled with an ESP, but took issue with the fact that no alternative PM limits were proposed for startup of FCCU equipped with other types of PM controls, or for any FCCU during periods of shutdown or hot standby. Regarding the proposed alternative for startup, which would provide an alternative in the form of an opacity limit when torch oil is in use, commenters stated that there are serious process safety concerns which prevent most FCCU ESPs from being operated when torch oil is in the regenerator, that is, during periods of startup, shutdown and hot standby. To avoid the possibility of a fire and explosion, the commenters claimed ESPs are usually de-energized and bypassed during these periods and, consequently, these FCCUs are generally unable to meet the proposed 30-percent opacity limit.

Several commenters stated that the EPA's limits on FCCU opacity during SSM are unreasonable and ignore the technical requirements for transitional operations of those units. The commenters indicated that they have ESPs located downstream of the CO boiler and claimed that for safety reasons the CO boiler cannot operate during startup, shutdown or hot standby. Further, a commenter indicated that the ESP cannot operate if the CO boiler is not operating and thus both the CO boiler and the ESP must be bypassed during startup, shutdown, and hot standby operations.

Another commenter stated that the EPA offers no data to support the achievability of this requirement in practice and discusses information for 26 startup/shutdown events that found that none complied with a 30-percent opacity requirement. Several commenters also noted that experience has shown that the 30-percent opacity limit is unachievable during these periods for FCCUs controlled with tertiary cyclones, when regenerator gas flow is below cyclone minimum design flow.

Several commenters suggested that the EPA establish a standard based on the operation of FCCU catalyst regenerators' internal cyclones that function to retain the catalyst in the regenerators and thereby minimize catalyst and metal HAP emissions from the regenerators. Additional control to meet the Refinery MACT 2 emission limit of not more than 1.0 lb PM/1,000 lbs coke burn-off is provided by a bag house, wet gas scrubber (WGS), ESP or tertiary (external) cyclone. The efficiency of a cyclone is a function of the inlet gas velocity. Assuring adequate velocity to the internal cyclones ensures that the catalyst sent to these additional controls is minimized and ensures that they are operating as effectively as possible. Similarly, even if the FCCU cannot meet the normal opacity limits during startup, shutdown or hot standby (*e.g.* due to the ESP being off-line for safety reasons or the tertiary cyclones or WGS operating at non-routine conditions), assuring adequate velocity to the internal regenerator cyclones will control and minimize particulate emissions. Several commenters stated support for another commenter's position that all FCCUs should be allowed the option of complying with a 20 feet/second minimum inlet velocity to the primary regenerator cyclones during periods of startup and shutdown, including hot standby, and these commenters provided additional technical explanations in their comments.

On the other hand, some commenters seemed to support the proposed opacity limits, but suggested minor revisions. One commenter noted that the SCAQMD has granted Valero's request for variances from visible emission standards during startup of the FCCU of up to 65-percent opacity for up to five minutes, in aggregate, during any 1-hour period, and 30-percent as an hourly average for the remaining period, during startup events. The application of this variance reflects the unavailability and/or ineffectiveness of the ESP during the startup condition. Another commenter recommended that either the opacity standard should be raised or the time period for averaging should be extended so FCCUs can be operated safely during SSM events and still remain in compliance.

Response: We have reviewed the data submitted by the commenters to support their assertion that the 30-percent opacity limit (determined on a 6-minute average basis) is not achievable during startup and shutdown events. While the data are limited, and it is unclear if the data provided are indicative of the performance achieved by the best performing sources, we do not have adequate data to refute the assertion that the 30-percent opacity limit (determined on a 6-minute average basis) is not achievable during startup and shutdown events. We considered the two options suggested by the commenters, the minimum velocity for the internal FCCU regenerator cyclones and the 30-percent hourly average opacity limit excluding 5 minutes not exceeding 65-percent opacity. Again, due to the limited data available during startup and shutdown events, we are not able to determine which requirement would provide greater HAP emissions reduction. However, we note that some facilities may not be required to have an opacity monitoring system in place and opacity monitoring is not applicable for FCCU controlled with wet scrubbers. Therefore, we find that the minimum internal cyclone inlet velocity requirement is more broadly applicable than the opacity limit. Also, based on the data provided by the commenters, the minimum internal cyclone inlet velocity requirement will provide PM (and therefore metal HAP) emissions reductions during startup and shutdown periods. Therefore, considering the available data, we conclude that MACT for FCCU startup and shutdown events is maintaining the minimum internal cyclone inlet velocity of 20 feet/second.

Comment: Several commenters stated that the EPA should provide alternate standards for startups of FCCU equipped with CO boilers and for any FCCU during periods of shutdown and hot standby. The commenters stated that the EPA incorrectly assumes that refiners are able to safely and reliably start up their FCCU with flue gas boilers in service and meet the normal operating limit of 500 ppm CO. They claimed that most refiners are unable to reliably start up their FCCU with flue gas boilers in service due to the design of the boiler and the fact that many boilers are not able to safely and reliably handle the transient FCCU operations that can occur during startup, shutdown, and hot standby. One commenter stated that FCCU built with CO boilers experience issues with flame stability due to fluctuating flue gas compositions and rates when starting up and shutting down. Accordingly, the commenter stated, startup and shutdown activities at FCCU using a boiler as an APCD are not currently meeting the Refinery MACT 2 standard of 500 ppm CO on a 1-hour basis, and this level of control does not qualify as the MACT floor. The commenter gave examples of facilities where FCCU, including those equipped with post-combustion control systems, do not consistently demonstrate compliance with a 500 ppm CO concentration standard during all startup and shutdown events.

Commenters stated that reliable boiler operation is critical to the overall refinery steam system and refineries must avoid jeopardizing boiler operation to prevent major upsets of process operations. A major upset or site-wide shutdown could result in flaring and emissions of HAP far in excess of that emitted while bypassing the CO boiler.

Commenters stated that combustion of torch oil in the FCCU regenerator during startup is one of the primary reasons the CO limit cannot be met during these operations. Torch oil is also used during shutdown to control the cooling rate (and potential equipment damage) and during hot standby and, thus, the normal CO standard cannot be met at these times either. Hot standby is used to hold an FCCU regenerator at operating temperature for outages where a regenerator shutdown is not needed and to avoid full FCCU shutdowns. Full cold shutdown also increases personnel exposures associated with removing catalyst and securing equipment. Additionally, this can produce additional emissions over maintaining the unit in hot standby. Commenters claimed that because of the variability of CO during torch oil operations, it is not possible for the EPA to establish a CAA section 112(d) standard for startup and shutdown activities at FCCU because refineries cannot measure a constant level of emissions reductions.

The commenters recommended expansion of the proposed standard of greater than 1-percent hourly average excess regenerator oxygen to all FCCU, including units with fired boilers. These commenters suggested that maintaining an adequate level of excess oxygen for the combustion of fuel in the regenerator is the best way to minimize CO and organic HAP emissions from FCCU during these periods.

Response: After reviewing the comments and discussing CO boiler operations with facility operators, we agree that the 1-percent minimum oxygen limit should be more broadly applicable to FCCU startup and shutdown regardless of the control device configuration and have revised the final rule accordingly.

Comment: Several commenters stated that the proposed alternative standards for SRP shutdowns should be extended to startups as well since the normal SRP emission limitation cannot always be achieved during SRP startups. Several commenters gave examples of startup activities where this relief is needed, and noted there may be other startup activities that also need this relief.

Response: For the control of sulfur HAP, we determined that incineration effectively controls these HAP. We were not aware that there would be unusual sulfur loads in the SRU tail gas during startup. We agree that the alternative standard we proposed for periods of shutdown is also the MACT floor for periods of startup because incineration meeting the limits proposed will achieve the MACT control requirements for sulfur HAP during periods of either startup or shutdown even though sulfur loadings during these periods may be elevated. For many SRU configurations, compliance during normal operations is demonstrated by monitoring SO_2 emissions. However, during startup and shutdown, high sulfur loadings in the SRU tail gas entering the incinerator will cause high SO_2 emissions even though sulfur HAP emissions are well controlled. Consequently, the proposed incinerator operating limits provide a better indication of sulfur HAP control during startup and shutdown than SO_2 emissions. Owners or operators that use incinerators or thermal oxidizers during normal operations may meet the site-specific temperature and excess oxygen operating limits that were determined based on their performance test during periods of startup and shutdown.

4. What is the rationale for our final approach and final decisions to address emissions during periods of SSM?

a. Refinery MACT 1

We did not receive comments regarding the proposed amendments to Table 6 of subpart CC of 40 CFR part 63; therefore, for the reasons provided in the preamble to the proposed rule, we finalizing these amendments as proposed.

We determined that it was overly burdensome and in most cases technically infeasible to consider every potential equipment or vessel opening and classify these ''openings'' (newly classified as MPV in the proposal) as either Group 1 or Group 2 MPV. We also determined that it is not always technically feasible, depending on the opening, to demonstrate compliance with the MPV emissions limitations. After considering the public comments, we determined it was appropriate to establish separate startup and shutdown provisions for MPV associated with process equipment openings. We reviewed state and local requirements and based the final rule requirements on the emissions limitations required to be followed by the best performing sources. Therefore, we are finalizing requirements for refinery owners or operators to open process equipment during these startup and shutdown events without directly permitting these ''vents'' as Group 1 or Group 2 MPV provided that the equipment is drained and purged to a closed system until the hydrocarbon content is less than or equal to 10-percent of the LEL. As described in further detail previously in this section, we have provided provisions for special cases where the 10-percent LEL limit cannot be demonstrated and provisions for less significant equipment openings, consistent with the practices used by the best performing facilities.

b. Refinery MACT 2

We did not receive significant comments regarding the proposed amendments to Table 44 to subpart UUU of 40 CFR part 63; therefore, we finalizing these amendments as proposed.

In response to comments, we determined that the limited provisions that were provided for startup only or for shutdown only were too limited and we have expanded the proposed provisions to both startup and shutdown regardless of control device used. For the FCCU organic HAP emissions limit, we are finalizing an alternative limit for periods of startup of no less than 1-percent oxygen in the exhaust gas as proposed, but we are extending that alternative limit to shutdown and to all FCCU in this final rule.

For the FCCU metal HAP emissions limit, we proposed a specific startup limit for FCCU controlled be an ESP of 30-percent opacity. We received comments along with limited data suggesting that this limit was not achievable. Commenters suggested that the best performing units maintain a minimum face velocity of at least 20 feet/second to minimize catalyst PM losses during startup and shutdowns. Operators of wet scrubbers also noted that they cannot maintain pressure drops and that one cannot meet the PM emissions limit normalized by coke burn-off rate when the coke burn-off rate approaches zero. Consequently, commenters stated that the alternative limits should be provided for startup and shutdown regardless of control device. Upon consideration of the comments, we determined that it was necessary to revise the proposed alternative to be based on minimum inlet face velocity to the FCCU regenerator internal cyclones and provide the alternative for both startup and shutdown. We also expanded this limit to all FCCU; however, we also required FCCU with wet scrubbers to meet only the liquid to gas ratio operating limit during periods of startup and shutdown to allow wet scrubbers to use a consistent compliance method at all times.

For SRU, we are finalizing an alternative standard during periods of startup and shutdown to use a flare that meets the operating limits included in the final rule or a thermal oxidizer or incinerator operated at a minimum hourly average temperature of 1,200 °F and a minimum hourly average outlet oxygen concentration of 2 volume percent (dry basis). We proposed these alternatives for periods of shutdown only, but based on comments received regarding startup issues, we determined that high sulfur loadings can occur during periods of startup and that the alternative limit proposed was appropriate for both startup and shutdown.

E. Technical Amendments to Refinery MACT 1 and 2

1. What other amendments did we propose for Refinery MACT 1 and 2?

We proposed a number of amendments to Refinery MACT 1 and 2 to address technical issues such as rule language clarifications and reference corrections. First, we proposed to amend Refinery MACT 1 to clarify what is meant by ''seal'' for open-ended valves and lines that are ''sealed'' by the cap, blind flange, plug, or second valve by stating that sealed means when there are no detectable emissions from the open-ended valve or line at or above an instrument reading of 500 ppm. Second, we also proposed electronic reporting requirements where owners or operators of petroleum refineries must submit electronic copies of required performance test and performance evaluation reports for compliance with Refinery MACT 1 and 2 by direct computer-to-computer electronic transfer using EPA-provided software. Third, we proposed to update the General Provisions Tables 6 (for Refinery MACT 1) and 44 (for Refinery MACT 2) to correct cross references and to incorporate additional sections of the General Provisions that are necessary to implement these rules.

2. How did the other amendments for Refinery MACT 1 and 2 change since proposal?

We are not finalizing the definition of ''seal'' for open-ended lines as proposed. We are finalizing changes to update the General Provisions cross-reference tables as proposed, with one minor change to provide an option for the administrator to issue guidance on performance test reporting timeframes in order to address issues relating to submittal of data to the ERT.

3. What key comments did we receive on the other amendments for Refinery MACT 1 and 2 and what are our responses?

Comment: Numerous commenters objected to the proposal to clarify the meaning of ''seal'' as it relates to open-ended line (OEL) standards. Commenters contend that there is no basis for the EPA to assert that the proposed definition merely ''clarifies'' an established interpretation of the term ''seal'' and stated that the proposed revision constitutes an illegal change in the requirements for OELs, and the clarification should not be finalized.

One commenter stated that none of the MACT standards in place before this proposal have stated or suggested that a ''sealed'' OEL is one with detectable emissions below 500 ppm. This commenter added this unique interpretation of the requirement to ''seal'' an OEL with a cap or plug is incompatible with the historical interpretation of this requirement by affected facilities and by the EPA, and the EPA has not issued any sort of definitive guidance or interpretation setting out this position. The commenter detailed numerous references to considerations the EPA has made relative to OEL requirements in LDAR programs. In addition to the examples cited, the commenter noted that in 2006, the EPA proposed to add a ''no detectible emissions'' limit and monitoring requirement for OELs to NSPS VV (71 FR 65317, November 7, 2006). Two commenters noted that the proposed monitoring was not finalized in either NSPS VV or VVa (72 FR 64860, November 16, 2007) because it was not considered BDT due to the low emission reductions and the cost effectiveness of the requirement. Another commenter agreed that there is no explanation provided for why this information could now support the need for a new OEL seal standard that requires monitoring to ensure compliance when it was deemed to be unjustified previously.

In addition, the commenter collected OEL monitoring data and submitted it to the EPA (see Docket Item No. EPA–HQ–OAR–2010–0869–0058). Based on these data, the commenter asserted that the existence of leaks from OELs that are not properly sealed is extremely low.

The commenter noted that the EPA is claiming this change is only a clarification of current requirements, allowing the EPA to bypass the need to cite a CAA authorization for this change to the existing CAA section 112(d)(2) standard or meet the process requirements associated with such a change, including providing emission reduction, cost and burden estimates in the record and the associated PRA Information Collection Request (ICR).

Several commenters claimed that this clarification would result in retroactive impact and also addressed the implication of the proposed change on other fugitive emissions standards. One commenter stated that the EPA cannot retroactively reinterpret the OEL requirements or define the word ''seal'' and added that the EPA should account for the thousands of additional monitoring events per year per refinery that this new requirement would add to LDAR programs and provide proper cost justification under CAA sections 112(d)(6) or 112(f)(2).

Several commenters also stated that the proposed definition will effectively change all equipment leak rules in parts 40 CFR parts 60, 61 and 63 and the change should not be finalized. One commenter added that by claiming this change is only a clarification of current requirements, the EPA would set a precedent applicable to all OELs in all industries subject to any similar OEL equipment leak requirement.

Response: We have decided not to finalize the proposed clarification of the term ''seal'' for OELs at this time. The fenceline monitoring requirements we are finalizing will detect any significant leaks from a cap, blind flange, plug or second valve that does not properly seal an OEL, as well as significant leaks from numerous other types of fugitive emission sources.

Comment: A few commenters stated that the proposed use of the ERT is not appropriate because the costs and burdens imposed are additive to the costs of producing and submitting the written report, and there is no benefit that justifies the additional cost. One commenter also stated that the EPA has not developed or articulated a reasonable approach to using information that would be uploaded to the ERT. The commenters recommended that the EPA remove this portion of the proposal until the ERT is demonstrated to handle all the information from refinery performance tests (rather than only portions), thereby eliminating the need for both written and electronic reporting and until the Agency demonstrates that it is using the electronic data to develop improved air quality emission factors.

Other commenters stated that the ERT requirement does not supersede or replace any state reporting requirements and thus the regulated industry will be subject to dual reporting requirements. These commenters disagreed with the preamble claim that eliminating the recordkeeping requirements for performance test reports is a burden savings, and stated that it may duplicate burdens already borne by the regulated community.

The commenters expressed further concern that duplicative reporting requirements will strain the regulated industry to comply with deadlines established by rule for report submittals. One commenter stated that there is no mechanism for obtaining extensions for special circumstances. Under proposed 40 CFR 63.655(h)(9)(i), all reports are due in 60 days. The commenter claimed that by not referencing reporting requirements to the General Provisions in 40 CFR 63.10(d)(2), there is no allowance for obtaining additional time due to unforeseen circumstances or due to the difficulties involved with completing particularly complex reports.

One commenter stated that the primary performance test method (Method 18) required for determining compliance is not currently included in the list of methods supported by the ERT. The commenter stated that the regulated community's experience with Method 18 is that it is a very broad methodology and can be exceptionally complex to execute and to report. The commenter stated that the EPA is aware that Method 18 reporting is complex, that it may be difficult to incorporate into the ERT, and that no time schedule has been defined for development or implementation for this method.

The commenter also stated that without formal notice of changes to the ERT, the regulated community is at risk of non-compliance. The only way for the regulated community to know that changes have occurred in the ERT is to monitor the Web site directly because the EPA does not formally announce changes to the ERT in the **Federal Register**. As such, it would be possible for a regulated entity to be unaware of changes made such as the incorporation of Method 18. The commenter expressed concern that the proposal language is an open-ended commitment subject to change without notice. The commenter stated that the EPA should clearly indicate when facilities would be required to use the ERT when new test methods are included in the ERT.

Response: We disagree that use of the ERT for completing stack test reports is an added cost and burden. While the requirement to report the results of stack tests with the ERT does not supersede state reporting requirements, we are aware of several states that already require the use of the ERT, and we are aware of more states that are considering requiring its use. We note that where states will not accept an electronic ERT submittal, the ERT provides an option to print the report, and the printed report can be mailed to the state agency. We have no reason to believe that the time savings in the ability to reuse data elements within reports does not, at a minimum, offset the cost incurred by printing out and mailing a copy of the report and the commenters have provided no support for their cost claims.

Furthermore, based on the analysis performed for the Electronic Reporting and Recordkeeping Requirements for the New Source Performance Standards Rulemaking (ERRRNSPS) (80 FR 15100), electronic reporting results in an overall cost savings to industry when annualized over a 20-year period. The cost savings is achieved through means such as standardization of data, embedded quality assurance checks, automatic calculation routines and reduced data entry through the ability to reuse data in files instead of starting from scratch with each test. As outlined in the ERRRNSPS, there are many benefits to electronic reporting. These benefits span all users of the data—the EPA, state and local regulators, the regulated entities and the public. We note that in the preamble to this proposed rule we provided a number of reasons why the use of the ERT will provide benefit going forward and that most of the benefits we outlined were longer-term benefits (*e.g.,* reducing burden of future information collection requests). Additionally, we note that in 2011, in response to Executive Order 13563, the EPA developed a plan [13] to periodically review its regulations to determine if they should be modified, streamlined, expanded or repealed in an effort to make regulations more effective and less burdensome. The plan includes replacing outdated paper reporting with electronic reporting. In keeping with this plan and the White House's Digital Government Strategy, [14] in 2013 the EPA issued an agency-wide policy specifying that new regulations will require reports to be electronic to the maximum extent possible. By requiring electronic submission of stack test reports in this rule, we are taking steps to implement this policy. We also disagree that we have not developed or articulated a reasonable approach to using information that would be uploaded to the ERT. To the contrary, we have discussed at length our plans for the use of stack test data collected via the ERT. In 2009, we published an advanced notice of proposed rulemaking (74 FR 52723) for the Emissions Factors Program Improvements. In that notice, we first outlined our intended approach for revising our emissions factors development procedures. This approach included using stack test data collected with the ERT. We reiterated this position in our ''Recommended Procedures for the Development of Emissions Factors and Use of the WebFIRE Database'' (*http://www.epa.gov/ttn/chief/efpac/procedures/procedures81213.pdf*), which was subject to public notice and comment before being finalized in 2013. Finally, we discussed uses of these data in the preamble to the proposed rule and at length in the preamble to the ERRRNSPS.

We think that it is a circular argument to say that the agency should eliminate the use of the ERT until it demonstrates that it is using the electronic data. It would be impossible for the agency to use data that it does not have. We can only use electronic data once we have electronic data. We do note that we are nearing completion of programming the WebFIRE database with our new emissions factor development procedures and anticipate running the routines on existing data sets in the near future.

We continue to improve and upgrade the ERT on an ongoing basis. The current version of the ERT supports 41 methods, including EPA Methods 1–4, 5, 5B, 5F, 25A 26, and 26A. We note that the ERT does not currently support EPA Method 18, and for performance tests using Method 18, the source will still have to produce a paper report. However, we are aware of the need to add Method 18 to the ERT, and we are currently looking at developing this capability. As noted in the ERRRNSPS, when new methods are added to the

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[13] EPA's ''Final Plan for Periodic Retrospective Reviews,'' August 2011. Available at: *http://www.epa.gov/regdarrt/retrospective/documents/eparetroreviewplan-aug2011.pdf.*

[14] Digital Government: Building a 21st Century Platform to Better Serve the American People, May 2012. Available at: *https://www.whitehouse.gov/sites/default/files/omb/egov/digital-government/digital-government-strategy.pdf.*

ERT, we will not only post them to the Web site; we will also send out a listserv notice to the Clearinghouse for Inventories and Emissions Factors (CHIEF) listserv. Information on joining the CHIEF listserv can be found at *http://www.epa.gov/ttn/chief/listserv.html#chief*. We are requiring the use of the ERT if the method is supported by the ERT, as listed on the ERT Web site (*http://www.epa.gov/ttn/chief/ert/ert_info.html*) at the time of the test. We do not agree that it is overly burdensome to check a Web site for updates prior to conducting a performance test.

We did revise the MACT 1 and 2 tables referencing reporting requirements to the general provisions (Table 6 for Refinery MACT 1 and Table 44 for Refinery MACT 2) to provide flexibility in the 60-day reporting timeline to accommodate unforeseen circumstances or difficulties involved with completing particularly complex reports.

4. What is the rationale for our final approach and final decisions for the other amendments for Refinery MACT 1 and 2?

We are not finalizing the definition of seal, as proposed. The fenceline monitoring work practice standard will detect any significant leaks from a cap, blind flange, plug or second valve that does not properly seal an OEL, as well as significant leaks from numerous other types of fugitive emission sources.

We are finalizing requirements for electronic reporting, as proposed, with a minor clarification. Specifically, we are revising Tables 6 in subpart CC and 44 in subpart UUU, which cross-reference the applicable provisions in the General Provisions to provide flexibility in the ERT 60-day reporting timeline. Refiners can seek approval from the EPA or a delegated state additional time for submittal of data due to unforeseen circumstances or due to the difficulties involved with completing particularly complex reports.

F. Technical Amendments to Refinery NSPS Subparts J and Ja

1. What amendments did we propose for Refinery NSPS Subparts J and Ja?

We proposed a number of amendments to Refinery NSPS subparts J and Ja to address reconsideration issues and minor technical clarifications. First, we proposed revisions to 40 CFR 60.100a(b) to include a provision that sources subject to Refinery NSPS subpart J could elect to comply instead with the provisions of Refinery NSPS subpart Ja.

Second, we proposed a series of amendments to the requirements for SRP in 40 CFR 60.102a, to clarify the applicable emission limits for different types of SRP based on whether oxygen enrichment is used. The amendments proposed also clarified that emissions averaging across a group of emission points within a given SRP is allowed for each of the different types of SRP, and that emissions averaging is specific to the SO_2 or reduced sulfur standards (and not to the 10 ppmv hydrogen sulfide (H_2S) limit). We also proposed a series of corresponding amendments in 40 CFR 60.106a to clarify the monitoring requirements, particularly when oxygen enrichment or emissions averaging is used. We also proposed clarifications in 40 CFR 60.106a to consistently use the term ‘‘reduced sulfur compounds’’ when referring to the emission limits and monitoring devices needed to comply with the reduced sulfur compound emission limits for sulfur recovery plants with reduction control systems not followed by incineration.

Third, we proposed amendments to 40 CFR 60.102a(g)(1) to clarify that CO boilers, while part of the FCCU affected facility, can also be FGCD.

Fourth, we proposed several revisions to 40 CFR 60.104a to clarify the performance testing requirements. We proposed revision to 40 CFR 60.104a(a) to clarify that an initial compliance demonstration is needed for the H_2S concentration limit in 40 CFR 60.103a(h). We proposed revisions to the annual PM testing requirement in 40 CFR 60.104a(b) to clarify that annually means once per calendar year, with an interval of at least 8 months but no more than 16 months between annual tests. We also proposed to amend 40 CFR 60.104a(f) to clarify that the provisions of that paragraph are specific to owners or operators of an FCCU or FCU that use a cyclone to comply with the PM emissions limit in 40 CFR 60.102a(b)(1) and not to facilities electing to comply with the PM emissions limit using a PM CEMS. We also proposed to amend 40 CFR 60.104a(j) to delete the requirements to measure flow for the H_2S concentration limit for fuel gas.

Fifth, we proposed several amendments to clarify the requirements for control device operating parameters in 40 CFR 60.105a. Specifically, we proposed amendments to 40 CFR 60.105a(b)(1)(ii)(A) to require corrective action be completed to repair faulty (leaking or plugged) air or water lines within 12 hours of identification of an abnormal pressure reading during the daily checks. We also proposed revisions to 40 CFR 60.105a(i) to specify that periods when abnormal pressure readings for a jet ejector-type wet scrubber (or other type of wet scrubber equipped with atomizing spray nozzles) are not corrected within 12 hours of identification and periods when a bag leak detection system alarm (for a fabric filter) is not alleviated within the time period specified in the rule are considered to be periods of excess emissions.

We also proposed amendments to 40 CFR 60.105(b)(1)(iv) and 60.107a(b)(1)(iv) to provide flexibility in span range to accommodate different manufacturers of the length-of-stain tubes. We also proposed to delete the last sentence in 40 CFR 60.105(b)(3)(iii).

Finally, we proposed clarification to the performance test requirements for the H_2S concentration limit for affected flares in 40 CFR 60.107a(e)(1)(ii) and (e)(2)(ii) to remove the distinction between flares with or without routine flow.

2. How did the amendments to Refinery NSPS Subparts J and Ja change since proposal?

We are making very few changes to the amendments proposed for Refinery NSPS subparts J and Ja. In response to comments, we are revising the NSPS requirements to replace the ‘‘measurement sensitivity’’ requirements with accuracy requirements consistent with those used in Refinery MACT 1 and 2. Specifically, we are revising 40 CFR 60.106a(a)(6)(i)(B) and (7)(i)(B) to require use of a flow sensor meeting an accuracy requirement of ±5-percent over the normal range of flow measured or 10-cubic-feet-per-minute, whichever is greater. We are also revising the flare accuracy requirements in 40 CFR 60.107a(f)(1)(ii) to require use of a flow sensor meeting an accuracy requirement of ±20-percent of the flow rate at velocities ranging from 0.1 to 1 feet per second and an accuracy of ±5-percent of the flow rate for velocities greater than 1-feet-per-second.

Finally, we are revising 40 CFR 60.101a(b) to correct an inadvertent error where the phrase ‘‘and delayed coking units’’ was not included in the proposed sentence revision.

3. What key comments did we receive on the amendments to Refinery NSPS Subparts J and Ja and what are our responses?

Comment: Two commenters noted concern with the term ‘‘measurement sensitivity’’ in proposed 40 CFR 60.106a(a)(6)(i)(B) and (a)(7)(i)(B) for sulfur recovery unit monitoring alternatives and in existing regulations 40 CFR 60.107a(f)(1)(ii) for flares because ‘‘sensitivity’’ is not a term found on typical monitoring system data sheets. Typical flow meter characteristics include terms such as accuracy and resolution and the commenters requested that the EPA revise the terminology to match the wording found in 40 CFR part 63, subpart CC, Table 13 for flow meters (*i.e.,* accuracy requirements). Additionally, several commenters suggested that the EPA flow monitor accuracy specifications are inconsistent with those in the SCAQMD Flare Rule and many refinery consent decrees. The commenters recommended revising both the flare flow meter sensitivity specification and accuracy specification in Refinery MACT 1 Table 13 and in Refinery NSPS subpart Ja to be consistent with the accuracy specification from the Shell Deer Park Consent Decree, Appendix 1.10, which specifies the required flare flow meter accuracy as ''±20% of reading over the velocity range of 0.1–1 feet per second (ft/s) and ±5% of reading over the velocity range of 1–250 ft/s.''

Response: We proposed the term ''measurement sensitivity'' in proposed 40 CFR 60.106a(a)(6)(i)(B) and (a)(7)(i)(B) to be internally consistent within Refinery NSPS subpart Ja [*i.e.,* consistent with the existing language in § 60.107a(f)(1)(ii)]. However, we agree with the commenters that this term may be unclear. This term is not defined in Refinery NSPS subpart Ja and it is not commonly used in the flow monitoring system's technical specification sheets. Therefore, to be consistent with the terminology used by instrument vendors and used in Refinery MACT 1 and 2, we are revising these sections to replace the term ''measurement sensitivity'' with ''accuracy.'' We are also revising the flow rate accuracy provisions specific for flares to provide an accuracy requirement of ±20-percent over the velocity range of 0.1–1 ft/s and ±5% for velocities exceeding 1 ft/s in 40 CFR 60.107a(f)(1)(ii) and in Table 13 of subpart CC. We are providing this provision specifically for flares because they commonly operate at high turndown ratios. For other flow measurements, we are retaining the 10-cubic-foot-per-minute accuracy requirement. We are also clarifying that the ±5-percent accuracy requirement for the SRU alternatives apply to the ''the normal range of flow measured'' consistent with the requirements in Refinery MACT 1 and 2.

Comment: One commenter stated that in the proposed revisions to 40 CFR 60.100a, (79 FR 36956), the EPA proposes to remove the phrase ''and delayed coker units'' from 40 CFR 60.100a(b). However, we state the compliance date for both flares and delayed coker units separately in the same paragraph. The commenter believes the EPA should explain the reason for and implications of the removal of this phrase.

Response: The removal of the phrase ''and delayed coking units'' from the first sentence in 40 CFR 60.100a(b) was an inadvertent error. The only revision that we intended to make in 40 CFR 60.100a was to allow owners or operators subject to subpart J to elect to comply with the requirements in subpart Ja. In the final amendments, we have included the phrase ''and delayed coking units'' in the first sentence in 40 CFR 60.100a(b).

4. What is the rationale for our final approach and final decisions for the amendments to Refinery NSPS Subparts J and Ja?

We are finalizing amendments for Refinery NSPS subparts J and Ja as proposed with minor revisions. In response to comments, we are revising the ''measurement sensitivity'' requirements to be an ''accuracy'' requirement. This change will make the requirements more clear and consistent between the flow meter requirements in the NSPS and the MACT standards since the same flow meter will be subject to each of these requirements. We are also providing a dual accuracy requirement for flare flow meters. This accuracy requirement is necessary because flares, which can have large diameters to accommodate high flows, are commonly operated at low flow rates. Together, this makes it technically infeasible for many flares to meet the lower flow 10 cfm accuracy requirement. Therefore, we are providing specific accuracy requirements for flares of ±20-percent over the velocity range of 0.1–1 ft/s and ±5-percent for velocities exceeding 1 ft/s, consistent with recent consent decrees and equipment vendor specifications.

Finally, we are revising the introductory phrase in the first sentence in 40 CFR 60.101a(b) to read ''Except for flares and delayed coking units . . .'' to correct an inadvertent error. We intended to revise this sentence only to include the proposed provision to allow sources subject to Refinery NSPS subpart J to comply with Refinery NSPS subpart Ja. The redline text posted on our Web site showed no revisions to this introductory phrase, but the amendatory text did not include the words ''and delayed coking units'' in this phrase. This was an inadvertent error, which we are correcting in the final rule.

V. Summary of Cost, Environmental and Economic Impacts and Additional Analyses Conducted

A. What are the affected facilities, the air quality impacts and cost impacts?

The sources affected by significant amendments to the petroleum refinery standards include flares, storage vessels, pressure relief devices, fugitive emissions and DCU. The amendments for other sources subject to one or more of the petroleum refinery standards are expected to have minimal air quality and cost impacts.

The total capital investment cost of the final amendments and standards is estimated at $283 million, $112 million from the final amendments for storage vessels, DCU and fenceline monitoring and $171 million from standards to ensure compliance. We estimate annualized costs of the final amendments for storage vessels, DCU and fenceline monitoring to be approximately $13.0 million, which includes an estimated $11.0 million for recovery of lost product and the annualized cost of capital. We also estimated annualized costs of the final standards to ensure compliance to be approximately $50.2 million. The final amendments for storage vessels, DCU and fenceline monitoring would achieve a nationwide HAP emission reduction of 1,323 tpy, with a concurrent reduction in VOC emissions of 16,660 tpy and a reduction in methane emissions of 8,700 metric tonnes per year. Table 2 of this preamble summarizes the cost and emission reduction impacts of the final amendments, and Table 3 of this preamble summarizes the costs of the final standards to ensure compliance.

TABLE 2—NATIONWIDE IMPACTS OF FINAL AMENDMENTS (2010$)

Affected source	Total capital investment (million $)	Total annualized cost without credit (million $/yr)	Product recovery credit (million $/yr)	Total annualized costs (million $/yr)	Methane emission reductions (metric tpy)	VOC emission reductions (tpy)	Cost effective-ness ($/ton VOC)	HAP emission reductions (tpy)	Cost effective-ness ($/ton HAP)
Storage Vessels	18.5	3.13	(8.16)	(5.03)		14,600	(345)	910	(5,530)
Delayed Coking Units	81	14.5	(2.80)	11.7	8,700	2,060	5,680	413	28,330
Fugitive Emissions (Fenceline Monitoring)	12.5	6.36		6.36					
Total	112	24.0	(11.0)	13.0	8,700	16,660	780	1,323	9,830

TABLE 3—NATIONWIDE COSTS OF FINAL AMENDMENTS TO ENSURE COMPLIANCE (2010$)

Affected Source	Total capital investment (million $)	Total annualized cost without credit (million $/yr)	Product recovery credit (million $/yr)	Total annualized costs (million $/yr)
Relief Device Monitoring	11.1	3.3		3.3
Flare Monitoring	160	46.5		46.5
FCCU Testing		0.4		0.4
Total	171	50.2		50.2

The impacts shown in Table 2 do not include costs, product recovery credits, or emissions reductions associated with any root cause analysis or corrective action taken in response to the final amendments for fenceline monitoring. The impacts shown in Table 3 do not include (i) the costs or emissions reductions associated with any root cause analysis and corrective action taken in response to the final source performance testing at the FCCUs, or (ii) emissions reductions associated with corrective action taken in response to pressure relief device or (iii) emissions reductions associated with the flare operating and monitoring provisions. The operational and monitoring requirements for flares at refineries have the potential to reduce excess emissions from flares by up to approximately 3,900 tpy of HAP and 33,000 tpy of VOC. The operational and monitoring requirements for flares also have the potential to reduce methane emissions by 25,800 metric tonnes per year while increasing emissions of carbon dioxide (CO2) and nitrous oxide by 267,000 metric tonnes per year and 2 metric tonnes per year, respectively, yielding a net reduction in GHG emissions of 377,000 metric tonnes per year of CO2 equivalents (CO_2e).

B. What are the economic impacts?

We performed a national economic impact analysis for petroleum product producers. All petroleum product refiners will incur annual compliance costs of less than 1-percent of their sales. For all firms, the minimum cost-to-sales ratio is <0.01-percent; the maximum cost-to-sales ratio is 0.87-percent; and the mean cost-to-sales ratio is 0.03-percent. Therefore, the overall economic impact of this proposed rule should be minimal for the refining industry and its consumers.

In addition, the EPA performed a screening analysis for impacts on small businesses by comparing estimated annualized engineering compliance costs at the firm-level to firm sales. The screening analysis found that the ratio of compliance cost to firm revenue falls below 1-percent for the 28 small companies likely to be affected by the proposal. For small firms, the minimum cost-to-sales ratio is <0.01-percent; the maximum cost-to-sales ratio is 0.62-percent; and the mean cost-to-sales ratio is 0.07-percent.

More information and details of this analysis is provided in the technical document ‘‘Economic Impact Analysis for Petroleum Refineries Proposed Amendments to the National Emissions Standards for Hazardous Air Pollutants’’, which is available in the docket for this rule (Docket ID No. EPA–HQ–OAR–2010–0682).

C. What are the benefits?

The final rule is anticipated to result in a reduction of 1,323 tpy of HAP (based on allowable emissions under the MACT standards) and 16,660 tpy of VOC, not including potential emission reductions that may occur as a result of the operating and monitoring requirements for flares and fugitive emission sources via fenceline monitoring. These avoided emissions will result in improvements in air quality and reduced negative health effects associated with exposure to air pollution of these emissions; however, we have not quantified or monetized the benefits of reducing these emissions for this rulemaking.

D. Impacts of This Rulemaking on Environmental Justice Populations

To examine the potential impacts on vulnerable populations (minority, low-income and indigenous communities) that might be associated with the Petroleum Refinery source categories addressed in this final rule, we evaluated the percentages of various social, demographic and economic groups in the at-risk populations living near the facilities where these sources are located and compared them to national averages. Our analysis of the demographics of the population with estimated risks greater than 1-in-1 million indicates potential disparities in risks between demographic groups including the African American, Other and Multiracial, Hispanic, Below the Poverty Level, and Over 25 without a High School Diploma when compared to the nationwide percentages of those groups. These groups will benefit the most from the emission reductions achieved by this final rulemaking, which is projected to result in 1 million fewer people exposed to risks greater than 1-in-1 million.

Additionally, these communities will benefit from this rulemaking, as this rulemaking for the first time ever requires fenceline monitoring, and reporting of fenceline data. The agency during the pre-proposal period and during the comment period received feedback from communities on the importance of having fenceline monitoring in their communities and the importance of communities having access to this data. The EPA believes that vulnerable communities will benefit from this data and the requirements that EPA has put in place in this rulemaking to manage fugitive emissions.

E. Impacts of This Rulemaking on Children's Health

Under Executive Order 13045 the EPA must evaluate the effects of the planned regulation on children's health and safety. This action's health and risk assessments are contained in section IV.A of this preamble. We believe we have adequately estimated risk for children, and we do not believe that the environmental health risks addressed by this action present a disproportionate risk to children. When the EPA derives exposure reference concentrations and unit risk estimates (URE) for HAP, it also considers the most sensitive populations identified (*i.e.*, children) in the available literature, and importantly, these are the values used in our risk assessments. With regard to children's potentially greater susceptibility to non-cancer toxicants, the assessments rely on the EPA (or comparable) hazard identification and dose-response values which have been developed to be protective for all subgroups of the general population, including children. With respect to cancer, the EPA uses the age-dependent adjustment factor approach, and applies these factors to carcinogenic pollutants that are known to act via mutagenic mode of action. Further details are provided in the ''Final Residual Risk Assessment for the Petroleum Refining Source Sector'', Docket ID No. EPA–HQ–OAR–2010–0682.

VI. Statutory and Executive Order Reviews

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

This action is an economically 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. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, ''Economic Impact Analysis: Petroleum Refineries—Final Amendments to the National Emissions Standards for Hazardous Air Pollutants and New Source Performance Standards'' is available in Docket ID Number EPA–HQ–OAR–2010–0682.

B. Paperwork Reduction Act (PRA)

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act*, 44 U.S.C. 3501 et se. The information collection requirements are not enforceable until OMB approves them.

Adequate recordkeeping and reporting are necessary to ensure compliance with these standards as required by the CAA. The ICR information collected from recordkeeping and reporting requirements is also used for prioritizing inspections and is of sufficient quality to be used as evidence in court.

The ICR document prepared by the EPA for the amendments to the Petroleum Refinery MACT standards for 40 CFR part 63, subpart CC has been assigned the EPA ICR number 1692.08. Burden changes associated with these amendments would result from new monitoring, recordkeeping and reporting requirements. The estimated annual increase in recordkeeping and reporting burden hours is 99,722 hours; the frequency of response is quarterly and semiannual for reports for all respondents that must comply with the rule's reporting requirements; and the estimated average number of likely respondents per year is 95 (this is the average in the second year). The cost burden to respondents resulting from the collection of information includes the total capital cost annualized over the equipment's expected useful life (about $18 million, which includes monitoring equipment for fenceline monitoring, pressure relief devices, and flares), a total operation and maintenance component (about $21 million per year for fenceline and flare monitoring), and a labor cost component (about $8.3 million per year, the cost of the additional 99,722 labor hours). Burden is defined at 5 CFR 1320.3(b).

The ICR document prepared by the EPA for the amendments to the Petroleum Refinery MACT standards for 40 CFR part 63, subpart UUU has been assigned the EPA ICR number 1844.06. Burden changes associated with these amendments would result from new testing, recordkeeping and reporting requirements being finalized with this action. The estimated average burden per response is 25 hours; the frequency of response ranges from annually up to every 5 years for respondents that have FCCU, and the estimated average number of likely respondents per year is 67. The cost burden to respondents resulting from the collection of information includes the performance testing costs (approximately $778,000 per year over the first 3 years for the initial PM and one-time HCN performance tests and $235,000 per year starting in the fourth year), and a labor cost component (approximately $410,000 per year for 4,940 additional labor hours). Burden is defined at 5 CFR 1320.3(b).

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

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities (SISNOSE) under the RFA. The small entities subject to the requirements of this action are small businesses, small organizations and small governmental jurisdictions. For purposes of assessing the impacts of this rule on small entities, a small entity is defined as: (1) A small business in the petroleum refining industry having 1,500 or fewer employees (Small Business Administration (SBA), 2011); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. Details of this analysis are presented in the economic impact analysis which can be found in the docket for this rule (Docket ID No. EPA–HQ–OAR–2010–0682).

D. 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. 1531–1538, and does not significantly or uniquely affect small governments. As discussed earlier in this preamble, these amendments result in nationwide costs of $63.2 million per year for the private sector. Additionally, the rule contains no requirements that apply to small governments and does not impose obligations upon them.

E. 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.

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

This action does not have tribal implications, as specified in Executive Order 13175. The final amendments impose no requirements on tribal governments. Thus, Executive Order 13175 does not apply to this action. Consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA consulted with tribal officials during the development of the proposed rule and specifically solicited comment on the proposed amendments from tribal officials.

G. 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 or safety risks addressed by this action present a disproportionate risk to children. This action's health and risk assessments are contained in section IV.A of this preamble.

H. 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. The overall economic impact of this final rule should be minimal for the refining industry and its consumers.

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

This rulemaking involves technical standards. Therefore, the EPA conducted searches for the Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). We also contacted voluntary consensus standards (VCS) organizations and accessed and searched their databases. We conducted searches for EPA Methods 18, 22, 320, 325A, and 325B of 40 CFR parts 60 and 63, appendix A. No applicable VCS were identified for EPA Method 22.

The following voluntary consensus standards were identified as acceptable alternatives to the EPA test methods for the purpose of this rule.

The voluntary consensus standard ISO 16017–2:2003(E) ''Air quality—Sampling and analysis of volatile organic compounds in ambient air, indoor air and workplace air by sorbent tube/thermal desorption/capillary gas chromatography. Part 2: Diffusive sampling'' is an acceptable alternative to Method 325A, Sections 1.2, 6.1 and 6.5 and Method 325B Sections 1.3, 7.1.2, 7.1.3, 7.1.4, 12.2.4, 13.0, A.1.1, and A.2. This voluntary consensus standard gives general guidance for the sampling and analysis of volatile organic compounds in air. It is applicable to indoor, ambient and workplace air. This standard is available at International Organization for Standardization, ISO Central Secretariat, Chemin de Blandonnet 8, CP 401, 1214 Vernier, Geneva, Switzerland. See *https://www.iso.org.*

The voluntary consensus standard BS EN 14662–4:2005 ''Ambient Air Quality: Standard Method for the Measurement of Benzene Concentrations—Part 4: Diffusive Sampling Followed By Thermal Desorption and Gas Chromatography'' is an acceptable alternative to Method 325A, Section 1.2 and Method 325B, Sections 1.3, 7.1.3, 7.1.4, 12.2.4, 13.0, A.1.1, and A.2. This voluntary consensus standard gives general guidance for the sampling and analysis of benzene in air by diffusive sampling, thermal desorption and capillary gas chromatography. This standard is available the European Committee for Standardization, Avenue Marnix 17—B–1000 Brussels. See *https://www.cen.eu.*

The voluntary consensus standard ASTM D6420–99 (2010) ''Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry'' is an acceptable alternative to EPA Method 18. This voluntary consensus standard employs a direct interface gas chromatography/mass spectrometer (GCMS) to identify and quantify a list of 36 volatile organic compounds (the compounds are listed in the method).

The voluntary consensus standard ASTM D6196–03 (Reapproved 2009) ''Standard Practice for Selection of Sorbents, Sampling, and Thermal Desorption Analysis Procedures for Volatile Organic Compounds in Air'' is an acceptable alternative to Method 325A, Sections 1.2 and 6.1, and Method 325B, Sections 1.3, 7.1.2, 7.1.3, 7.1.4, 13.0, A.1.1, and A.2. This voluntary consensus standard is intended to assist in the selection of sorbents and procedures for the sampling and analysis of ambient, indoor, and workplace atmospheres for a variety of common volatile organic compounds.

The voluntary consensus standards ASTM D1945–03 and later revision ASTM D1945–14 ''Standard Test Method for Analysis of Natural Gas by Gas Chromatography'' are acceptable for natural gas analysis. This voluntary consensus standard covers the determination of the chemical composition of natural gases and similar gaseous mixtures. This test method may be abbreviated for the analysis of lean natural gases containing negligible amounts of hexanes and higher hydrocarbons, or for the determination of one or more components, as required.

The voluntary consensus standard ASTM UOP539–12 ''Refinery Gas Analysis by GC'' is acceptable for refinery gas analysis. This voluntary consensus standard is for determining the composition of refinery gas streams or vaporized liquefied petroleum gas using a preconfigured, commercially available gas chromatograph.

The voluntary consensus standard ASTM D6348–03 (Reapproved 2010) including Annexes A1 through A8, ''Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy'' is an acceptable alternative to EPA Method 320. This voluntary consensus standard is a field test method that employs an extractive sampling system to direct stationary source effluent to an FTIR spectrometer for the identification and quantification of gaseous compounds. This field test method provides near real time analysis of extracted gas samples from stationary sources.

The voluntary consensus standard ASTM D6348–12e1 ''Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy'' is an acceptable alternative to EPA Method 320 with the following two caveats: (1) The test plan preparation and implementation in the Annexes to ASTM D 6348–03 (Reapproved 2010), Sections A1 through A8 are mandatory; and (2) In ASTM D6348–03 (Reapproved 2010) Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5). In order for the test data to be acceptable for a compound, %R must be 70% ≥ R ≤ 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 Result = (*Measured Concentration in the Stack* × *100*)/*% R.*

This voluntary consensus standard is a field test method that employs an extractive sampling system to direct stationary source effluent to an FTIR spectrometer for the identification and quantification of gaseous compounds. This field test method provides near real time analysis of extracted gas samples from stationary sources.

The EPA solicited comments on VCS and invited the public to identify potentially-applicable VCS; however, we did not receive comments regarding this aspect of 40 CFR part 60, subparts J and Ja, and part 63, subparts CC, UUU, and Y. Under 40 CFR 63.7(f) and 63.8(f), a source may apply to the EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications, or procedures in this final rule.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations in the U.S. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies. The EPA has this goal for all communities and persons by working to ensure that everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn and work.

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. As discussed in section V.D. of this preamble, the EPA conducted an analysis of the characteristics of the population with greater than 1-in-1 million risk living within 50 km of the 142 refineries affected by this rulemaking and determined that there are more African-Americans, Other and multiracial groups, Hispanics, low-income individuals, individuals with less than a high school diploma compared to national averages. Therefore, these populations are expected to experience the benefits of the risk reductions associated with this rule. The results of this evaluation are contained in two technical reports, ‘‘Risk and Technology Review—Analysis of Socio-Economic Factors for Populations Living Near Petroleum Refineries’’, available in the docket for this action (See Docket ID Nos. EPA–HQ–OAR–2010–0682–0226 and -0227). Additionally, a discussion of the final risk analysis is included in Sections IV.A and V.D of this preamble.

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations because it maintains or increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low-income or indigenous populations. Further, the EPA believes that implementation of this rule will provide an ample margin of safety to protect public health of all demographic groups.

K. Congressional Review Act (CRA)

This action is subject to the 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 a ‘‘major rule’’ as defined by 5 U.S.C. 804(2).

List of Subjects

40 CFR Part 60

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

40 CFR Part 63

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

Dated: September 29, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended 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 J—Standards of Performance for Petroleum Refineries

■ 2. Section 60.105 is amended by revising paragraphs (b)(1)(iv) and (b)(3)(iii) to read as follows:

§ 60.105 Monitoring of emissions and operations.

* * * * *

(b) * * *

(1) * * *

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppmv. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes (‘‘length-of-stain tube’’ type measurement) following the ‘‘Gas Processors Association Standard 2377–86 (incorporated by reference—see § 60.17), using tubes with a maximum span between 10 and 40 ppmv inclusive when $1 \leq N \leq 10$, where N = number of pump strokes, to test the applicant fuel gas stream for H_2S; and

* * * * *

(3) * * *

(iii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application and the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin H_2S monitoring using daily stain sampling to demonstrate compliance using length-of stain tubes with a maximum span between 200 and 400 ppmv inclusive when 1≤N≤5, where N = number of pump strokes. The owner or operator must begin monitoring according to the requirements in paragraph (a)(1) or (2) of this section as soon as practicable but in no case later than 180 days after the operation change. During daily stain tube sampling, a daily sample exceeding 162 ppmv is an exceedance of the 3-hour H_2S concentration limit.

* * * * *

Subpart Ja—Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

■ 3. Section 60.100a is amended by revising the first sentence of paragraph (b) to read as follows:

§ 60.100a Applicability, designation of affected facility, and reconstruction.

* * * * *

(b) Except for flares and delayed coking units, the provisions of this subpart apply only to affected facilities under paragraph (a) of this section which either commence construction, modification or reconstruction after May 14, 2007, or elect to comply with the provisions of this subpart in lieu of complying with the provisions in subpart J of this part. * * *

* * * * *

■ 4. Section 60.101a is amended by:

■ a. Revising the definition of ‘‘Corrective action’’; and

■ b. Adding, in alphabetical order, a definition for ‘‘Sour water’’.

The revision and addition read as follows:

§ 60.101a Definitions.

* * * * *

Corrective action means the design, operation and maintenance changes that one takes consistent with good engineering practice to reduce or eliminate the likelihood of the recurrence of the primary cause and any other contributing cause(s) of an event identified by a root cause analysis as having resulted in a discharge of gases from an affected facility in excess of specified thresholds.

* * * * *

Sour water means water that contains sulfur compounds (usually H_2S) at concentrations of 10 parts per million by weight or more.

* * * * *

■ 5. Section 60.102a is amended by revising paragraphs (b)(1)(i) and (iii), (f), and (g)(1) introductory text to read as follows:

§ 60.102a Emissions limitations.

* * * * *

(b) * * *

(1) * * *

(i) 1.0 gram per kilogram (g/kg) (1 pound (lb) per 1,000 lb) coke burn-off or, if a PM continuous emission monitoring system (CEMS) is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each modified or reconstructed FCCU.

* * * * *

(iii) 1.0 g/kg (1 lb/1,000 lb) coke burn-off or, if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each affected FCU.

* * * * *

(f) Except as provided in paragraph (f)(3) of this section, each owner or operator of an affected sulfur recovery plant shall comply with the applicable emission limits in paragraph (f)(1) or (2) of this section.

(1) For a sulfur recovery plant with a design production capacity greater than 20 long tons per day (LTD), the owner or operator shall comply with the applicable emission limit in paragraph (f)(1)(i) or (ii) of this section. If the sulfur recovery plant consists of multiple process trains or release points, the owner or operator shall comply with the applicable emission limit for each process train or release point individually or comply with the applicable emission limit in paragraph (f)(1)(i) or (ii) as a flow rate weighted average for a group of release points from the sulfur recovery plant provided that flow is monitored as specified in § 60.106a(a)(7); if flow is not monitored as specified in § 60.106a(a)(7), the owner or operator shall comply with the applicable emission limit in paragraph (f)(1)(i) or (ii) for each process train or release point individually. For a sulfur recovery plant with a design production capacity greater than 20 long LTD and a reduction control system not followed by incineration, the owner or operator shall also comply with the H_2S emission limit in paragraph (f)(1)(iii) of this section for each individual release point.

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere (SO_2) in excess of the emission limit calculated using Equation 1 of this section. For Claus units that use only ambient air in the Claus burner or that elect not to monitor O_2 concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, this SO_2 emissions limit is 250 ppmv (dry basis) at zero percent excess air.

$$E_{LS} = k_1 \times \left(-0.038 \times (\%O_2)^2 + 11.53 \times \%O_2 + 25.6\right) \qquad \text{(Eq. 1)}$$

Where:

E_{LS} = Emission limit for large sulfur recovery plant, ppmv (as SO_2, dry basis at zero percent excess air);

k_1 = Constant factor for emission limit conversion: $k_1 = 1$ for converting to the SO_2 limit for a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration and $k_1 = 1.2$ for converting to the reduced sulfur compounds limit for a sulfur recovery plant with a reduction control system not followed by incineration; and

$\%O_2$ = O_2 concentration of the air/oxygen mixture supplied to the Claus burner, percent by volume (dry basis). If only ambient air is used for the Claus burner or if the owner or operator elects not to monitor O_2 concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, use 20.9% for $\%O_2$.

(ii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing reduced sulfur compounds in excess of the emission limit calculated using Equation 1 of this section. For Claus units that use only ambient air in the Claus burner or for non-Claus sulfur recovery plants, this reduced sulfur compounds emission limit is 300 ppmv calculated as ppmv SO_2 (dry basis) at 0-percent excess air.

(iii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing hydrogen sulfide (H_2S) in excess of 10 ppmv calculated as ppmv SO_2 (dry basis) at zero percent excess air.

(2) For a sulfur recovery plant with a design production capacity of 20 LTD or less, the owner or operator shall comply with the applicable emission limit in paragraph (f)(2)(i) or (ii) of this section. If the sulfur recovery plant consists of multiple process trains or release points, the owner or operator may comply with the applicable emission limit for each process train or release point individually or comply with the applicable emission limit in paragraph (f)(2)(i) or (ii) as a flow rate weighted average for a group of release points from the sulfur recovery plant provided that flow is monitored as specified in § 60.106a(a)(7); if flow is not monitored as specified in § 60.106a(a)(7), the owner or operator shall comply with the applicable emission limit in paragraph (f)(2)(i) or (ii) for each process train or release point individually. For a sulfur recovery plant with a design production capacity of 20 LTD or less and a reduction control system not followed by incineration, the owner or operator shall also comply with the H_2S emission limit in paragraph (f)(2)(iii) of this section for each individual release point.

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing SO_2 in excess of the emission limit calculated using Equation 2 of this section. For Claus units that use only ambient air in the Claus burner or that elect not to monitor O_2 concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, this SO_2 emission limit is 2,500 ppmv (dry basis) at zero percent excess air.

$$E_{SS} = k_1 \times \left(-0.38 \times (\%O_2)^2 + 115.3 \times \%O_2 + 256\right) \qquad \text{(Eq. 2)}$$

Where:

E_{SS} = Emission limit for small sulfur recovery plant, ppmv (as SO_2, dry basis at zero percent excess air);

k_1 = Constant factor for emission limit conversion: $k_1 = 1$ for converting to the SO_2 limit for a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration and $k_1 = 1.2$ for converting to the reduced sulfur compounds limit for a sulfur recovery plant with a reduction control system not followed by incineration; and

$\%O_2$ = O_2 concentration of the air/oxygen mixture supplied to the Claus burner, percent by volume (dry basis). If only ambient air is used in the Claus burner or if the owner or operator elects not to monitor O_2 concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, use 20.9% for $\%O_2$.

(ii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing reduced sulfur compounds in excess of the emission limit calculated using Equation 2 of this section. For Claus units that use only ambient air in the Claus burner or for non-Claus sulfur recovery plants, this reduced sulfur compounds emission limit is 3,000 ppmv calculated as ppmv SO_2 (dry basis) at zero percent excess air.

(iii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing H_2S in excess of 100 ppmv calculated as ppmv SO_2 (dry basis) at zero percent excess air.

(3) The emission limits in paragraphs (f)(1) and (2) of this section shall not apply during periods of maintenance of the sulfur pit, which shall not exceed 240 hours per year. The owner or operator must document the time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods. Examples of these measures include not adding fresh sulfur or shutting off vent fans.

(g) * * *

(1) Except as provided in (g)(1)(iii) of this section, for each fuel gas combustion device, the owner or operator shall comply with either the emission limit in paragraph (g)(1)(i) of this section or the fuel gas concentration limit in paragraph (g)(1)(ii) of this section. For CO boilers or furnaces that are part of a fluid catalytic cracking unit or fluid coking unit affected facility, the owner or operator shall comply with the fuel gas concentration limit in paragraph (g)(1)(ii) for all fuel gas streams combusted in these units.

* * * * *

■ 6. Section 60.104a is amended by:

■ a. Revising the first sentence of paragraph (a) and paragraphs (b), (f) introductory text, and (h) introductory text;

■ b. Adding paragraph (h)(6); and

■ c. Removing and reserving paragraphs (j)(1) through (3).

The revisions and additions read as follows:

§ 60.104a Performance tests.

(a) The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant and fuel gas combustion device to demonstrate initial compliance with each applicable emissions limit in § 60.102a and conduct a performance test for each flare to demonstrate initial compliance with the H_2S concentration requirement in § 60.103a(h) according to the requirements of § 60.8. * * *

(b) The owner or operator of a FCCU or FCU that elects to monitor control device operating parameters according to the requirements in § 60.105a(b), to use bag leak detectors according to the requirements in § 60.105a(c), or to use COMS according to the requirements in § 60.105a(e) shall conduct a PM performance test at least annually (*i.e.*, once per calendar year, with an interval of at least 8 months but no more than 16 months between annual tests) and furnish the Administrator a written report of the results of each test.

* * * * *

(f) The owner or operator of an FCCU or FCU that uses cyclones to comply with the PM per coke burn-off emissions limit in § 60.102a(b)(1) shall establish a site-specific opacity operating limit according to the procedures in paragraphs (f)(1) through (3) of this section.

* * * * *

(h) The owner or operator shall determine compliance with the SO_2 emissions limits for sulfur recovery plants in § 60.102a(f)(1)(i) and (f)(2)(i) and the reduced sulfur compounds and H_2S emissions limits for sulfur recovery plants in § 60.102a(f)(1)(ii), (f)(1)(iii), (f)(2)(ii), and (f)(2)(iii) using the following methods and procedures:

* * * * *

(6) If oxygen or oxygen-enriched air is used in the Claus burner and either Equation 1 or 2 of this subpart is used to determine the applicable emissions limit, determine the average O_2 concentration of the air/oxygen mixture supplied to the Claus burner, in percent by volume (dry basis), for the performance test using all hourly average O_2 concentrations determined

during the test runs using the procedures in § 60.106a(a)(5) or (6).

* * * * *

■ 7. Section 60.105a is amended by:

■ a. Revising paragraphs (b)(1)(i), (b)(1)(ii)(A), (b)(2), (h)(1), (h)(3)(i), and (i)(1);

■ b. Redesignating paragraphs (i)(2) through (6) as (i)(3) through (7);

■ c. Adding paragraph (i)(2); and

■ d. Revising newly redesignated paragraph (i)(7).

The revisions and additions read as follows:

§ 60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).

* * * * *

(b) * * *

(1) * * *

(i) For units controlled using an electrostatic precipitator, the owner or operator shall use CPMS to measure and record the hourly average total power input and secondary current to the entire system.

(ii) * * *

(A) As an alternative to pressure drop, the owner or operator of a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles must conduct a daily check of the air or water pressure to the spray nozzles and record the results of each check. Faulty (*e.g.*, leaking or plugged) air or water lines must be repaired within 12 hours of identification of an abnormal pressure reading.

* * * * *

(2) For use in determining the coke burn-off rate for an FCCU or FCU, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring the concentrations of CO_2, O_2 (dry basis), and if needed, CO in the exhaust gases prior to any control or energy recovery system that burns auxiliary fuels. A CO monitor is not required for determining coke burn-off rate when no auxiliary fuel is burned and a continuous CO monitor is not required in accordance with paragraph (h)(3) of this section.

(i) The owner or operator shall install, operate, and maintain each CO_2 and O_2 monitor according to Performance Specification 3 of appendix B to this part.

(ii) The owner or operator shall conduct performance evaluations of each CO_2 and O_2 monitor according to the requirements in § 60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Method 3 of appendix A–3 to this part for conducting the relative accuracy evaluations.

(iii) If a CO monitor is required, the owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of appendix B to this part. If this CO monitor also serves to demonstrate compliance with the CO emissions limit in § 60.102a(b)(4), the span value for this instrument is 1,000 ppm; otherwise, the span value for this instrument should be set at approximately 2 times the typical CO concentration expected in the FCCU of FCU flue gas prior to any emission control or energy recovery system that burns auxiliary fuels.

(iv) If a CO monitor is required, the owner or operator shall conduct performance evaluations of each CO monitor according to the requirements in § 60.13(c) and Performance Specification 4 of appendix B to this part. The owner or operator shall use Method 10, 10A, or 10B of appendix A–3 to this part for conducting the relative accuracy evaluations.

(v) The owner or operator shall comply with the quality assurance requirements of procedure 1 of appendix F to this part, including quarterly accuracy determinations for CO_2 and CO monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

* * * * *

(h) * * *

(1) The owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of appendix B to this part. The span value for this instrument is 1,000 ppmv CO.

* * * * *

(3) * * *

(i) The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that meets the requirements of Performance Specification 4 or 4A of appendix B to this part. The span value shall be 100 ppmv CO instead of 1,000 ppmv, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppmv CO, whichever is greater. For instruments that are identical to Method 10 of appendix A–4 to this part and employ the sample conditioning system of Method 10A of appendix A–4 to this part, the alternative relative accuracy test procedure in section 10.1 of Performance Specification 2 of appendix B to this part may be used in place of the relative accuracy test.

* * * * *

(i) * * *

(1) If a CPMS is used according to paragraph (b)(1) of this section, all 3-hour periods during which the average PM control device operating characteristics, as measured by the continuous monitoring systems under paragraph (b)(1), fall below the levels established during the performance test. If the alternative to pressure drop CPMS is used for the owner or operator of a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles, each day in which abnormal pressure readings are not corrected within 12 hours of identification.

(2) If a bag leak detection system is used according to paragraph (c) of this section, each day in which the cause of an alarm is not alleviated within the time period specified in paragraph (c)(3) of this section.

* * * * *

(7) All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under paragraph (h) of this section exceeds 500 ppmv or, if applicable, all 1-hour periods during which the average temperature and O_2 concentration as measured by the continuous monitoring systems under paragraph (h)(4) of this section fall below the operating limits established during the performance test.

■ 8. Section 60.106a is amended by:

■ a. Revising paragraph (a)(1)(i);

■ b. Adding paragraphs (a)(1)(iv) through (vii);

■ c. Revising paragraphs (a)(2) introductory text, (a)(2)(i) and (ii), and the first sentence of paragraph (a)(2)(iii);

■ d. Removing paragraphs (a)(2)(iv) and (v);

■ e. Redesignating paragraphs (a)(2)(vi) through (ix) as (a)(2)(iv) through (vii);

■ f. Revising the first sentence of paragraph (a)(3) introductory text and paragraph (a)(3)(i);

■ g. Adding paragraphs (a)(4) through (7); and

■ h. Revising paragraphs (b)(2) and (3).

The revisions and additions read as follows:

§ 60.106a Monitoring of emissions and operations for sulfur recovery plants.

(a) * * *

(1) * * *

(i) The span value for the SO_2 monitor is two times the applicable SO_2 emission limit at the highest O_2 concentration in the air/oxygen stream used in the Claus burner, if applicable.

* * * * *

(iv) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to this part.

(v) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(vi) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of § 60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Methods 3, 3A, or 3B of appendix A–2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to this part.

(vii) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to this part for each monitor, including annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(2) For sulfur recovery plants that are subject to the reduced sulfur compounds emission limit in § 60.102a(f)(1)(ii) or (f)(2)(ii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of reduced sulfur compounds and O_2 emissions into the atmosphere. The reduced sulfur compounds emissions shall be calculated as SO_2 (dry basis, zero percent excess air).

(i) The span value for the reduced sulfur compounds monitor is two times the applicable reduced sulfur compounds emission limit as SO_2 at the highest O_2 concentration in the air/oxygen stream used in the Claus burner, if applicable.

(ii) The owner or operator shall install, operate, and maintain each reduced sulfur compounds CEMS according to Performance Specification 5 of appendix B to this part.

(iii) The owner or operator shall conduct performance evaluations of each reduced sulfur compounds monitor according to the requirements in § 60.13(c) and Performance Specification 5 of appendix B to this part. * * *

* * * * *

(3) In place of the reduced sulfur compounds monitor required in paragraph (a)(2) of this section, the owner or operator may install, calibrate, operate, and maintain an instrument using an air or O_2 dilution and oxidation system to convert any reduced sulfur to SO_2 for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of the total resultant SO_2. * * *

(i) The span value for this monitor is two times the applicable reduced sulfur compounds emission limit as SO_2 at the highest O_2 concentration in the air/oxygen stream used in the Claus burner, if applicable.

* * * * *

(4) For sulfur recovery plants that are subject to the H_2S emission limit in § 60.102a(f)(1)(iii) or (f)(2)(iii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of H_2S, and O_2 emissions into the atmosphere. The H_2S emissions shall be calculated as SO_2 (dry basis, zero percent excess air).

(i) The span value for this monitor is two times the applicable H_2S emission limit.

(ii) The owner or operator shall install, operate, and maintain each H_2S CEMS according to Performance Specification 7 of appendix B to this part.

(iii) The owner or operator shall conduct performance evaluations for each H_2S monitor according to the requirements of § 60.13(c) and Performance Specification 7 of appendix B to this part. The owner or operator shall use Methods 11 or 15 of appendix A–5 to this part or Method 16 of appendix A–6 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to this part.

(iv) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to this part.

(v) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(vi) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of § 60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Methods 3, 3A, or 3B of appendix A–2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to this part.

(vii) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to this part for each monitor, including annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(5) For sulfur recovery plants that use oxygen or oxygen enriched air in the Claus burner and that elects to monitor O_2 concentration of the air/oxygen mixture supplied to the Claus burner, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the O_2 concentration of the air/oxygen mixture supplied to the Claus burner in order to determine the allowable emissions limit.

(i) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to this part.

(ii) The span value for the O_2 monitor shall be 100 percent.

(iii) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of § 60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Methods 3, 3A, or 3B of appendix A–2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to this part.

(iv) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to this part for each monitor, including annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(v) The owner or operator shall use the hourly average O_2 concentration from this monitor for use in Equation 1 or 2 of § 60.102a(f), as applicable, for each hour and determine the allowable emission limit as the arithmetic average of 12 contiguous 1-hour averages (*i.e.*, the rolling 12-hour average).

(6) As an alternative to the O_2 monitor required in paragraph (a)(5) of this section, the owner or operator may install, calibrate, operate, and maintain a CPMS to measure and record the volumetric gas flow rate of ambient air and oxygen-enriched gas supplied to the Claus burner and calculate the hourly average O_2 concentration of the air/oxygen mixture used in the Claus burner as specified in paragraphs (a)(6)(i) through (iv) of this section in order to determine the allowable emissions limit as specified in paragraphs (a)(6)(v) of this section.

(i) The owner or operator shall install, calibrate, operate and maintain each flow monitor according to the manufacturer's procedures and specifications and the following requirements.

(A) Locate the monitor in a position that provides a representative measurement of the total gas flow rate.

(B) Use a flow sensor meeting an accuracy requirement of ±5 percent over the normal range of flow measured or 10 cubic feet per minute, whichever is greater.

(C) Use a flow monitor that is maintainable online, is able to continuously correct for temperature, pressure and, for ambient air flow monitor, moisture content, and is able to record dry flow in standard conditions (as defined in § 60.2) over one-minute averages.

(D) At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor.

(E) Recalibrate the flow monitor in accordance with the manufacturer's procedures and specifications biennially (every two years) or at the frequency specified by the manufacturer.

(ii) The owner or operator shall use 20.9 percent as the oxygen content of the ambient air.

(iii) The owner or operator shall use product specifications (*e.g.,* as reported in material safety data sheets) for percent oxygen for purchased oxygen. For oxygen produced onsite, the percent oxygen shall be determined by periodic measurements or process knowledge.

(iv) The owner or operator shall calculate the hourly average O_2 concentration of the air/oxygen mixture used in the Claus burner using Equation 10 of this section:

$$\%O_2 = \left(\frac{20.9 \times Q_{air} + \%O_{2,oxy} \times Q_{oxy}}{Q_{air} + Q_{oxy}} \right) \qquad \text{(Eq. 10)}$$

Where:

$\%O_2$ = O_2 concentration of the air/oxygen mixture used in the Claus burner, percent by volume (dry basis);
20.9 = O_2 concentration in air, percent dry basis;
Q_{air} = Volumetric flow rate of ambient air used in the Claus burner, dscfm;
$\%O_{2,oxy}$ = O_2 concentration in the enriched oxygen stream, percent dry basis; and
Q_{oxy} = Volumetric flow rate of enriched oxygen stream used in the Claus burner, dscfm.

(v) The owner or operator shall use the hourly average O_2 concentration determined using Equation 8 of § 60.104a(d)(8) for use in Equation 1 or 2 of § 60.102a(f), as applicable, for each hour and determine the allowable emission limit as the arithmetic average of 12 contiguous 1-hour averages (*i.e.,* the rolling 12-hour average).

(7) Owners or operators of a sulfur recovery plant that elects to comply with the SO_2 emission limit in § 60.102a(f)(1)(i) or (f)(2)(i) or the reduced sulfur compounds emission limit in § 60.102a(f)(1)(ii) or (f)(2)(ii) as a flow rate weighted average for a group of release points from the sulfur recovery plant rather than for each process train or release point individually shall install, calibrate, operate, and maintain a CPMS to measure and record the volumetric gas flow rate of each release point within the group of release points from the sulfur recovery plant as specified in paragraphs (a)(7)(i) through (iv) of this section.

(i) The owner or operator shall install, calibrate, operate and maintain each flow monitor according to the manufacturer's procedures and specifications and the following requirements.

(A) Locate the monitor in a position that provides a representative measurement of the total gas flow rate.

(B) Use a flow sensor meeting an accuracy requirement of ±5 percent over the normal range of flow measured or 10 cubic feet per minute, whichever is greater.

(C) Use a flow monitor that is maintainable online, is able to continuously correct for temperature, pressure, and moisture content, and is able to record dry flow in standard conditions (as defined in § 60.2) over one-minute averages.

(D) At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor.

(E) Recalibrate the flow monitor in accordance with the manufacturer's procedures and specifications biennially (every two years) or at the frequency specified by the manufacturer.

(ii) The owner or operator shall correct the flow to 0 percent excess air using Equation 11 of this section:

$$Q_{adj} = Q_{meas} \left[\left(20.9 - \%O_2\right) \Big/ 20.9_c \right] \qquad \text{(Eq. 11)}$$

Where:

Q_{adj} = Volumetric flow rate adjusted to 0 percent excess air, dry standard cubic feet per minute (dscfm);
C_{meas} = Volumetric flow rate measured by the flow meter corrected to dry standard conditions, dscfm;
20.9_c = 20.9 percent O_2 − 0.0 percent O_2 (defined O_2 correction basis), percent;
20.9 = O_2 concentration in air, percent; and
$\%O_2$ = O_2 concentration measured on a dry basis, percent.

(iii) The owner or operator shall calculate the flow weighted average SO_2 or reduced sulfur compounds concentration for each hour using Equation 12 of this section:

$$C_{ave} = \frac{\sum_{n=1}^{N} \left(C_n \times Q_{adj,n}\right)}{\sum_{n=1}^{N} Q_{adj,n}} \qquad \text{(Eq. 12)}$$

Where:

C_{ave} = Flow weighted average concentration of the pollutant, ppmv (dry basis, zero percent excess air). The pollutant is either SO_2 (if complying with the SO_2 emission limit in § 60.102a(f)(1)(i) or (f)(2)(i)) or reduced sulfur compounds (if complying with the reduced sulfur compounds emission limit in § 60.102a(f)(1)(ii) or (f)(2)(ii));

N = Number of release points within the group of release points from the sulfur recovery plant for which emissions averaging is elected;

C_n = Pollutant concentration in the n^{th} release point within the group of release points from the sulfur recovery plant for which emissions averaging is elected, ppmv (dry basis, zero percent excess air);

$Q_{adj,n}$ = Volumetric flow rate of the n^{th} release point within the group of release points from the sulfur recovery plant for which emissions averaging is elected, dry standard cubic feet per minute (dscfm, adjusted to 0 percent excess air).

(iv) For sulfur recovery plants that use oxygen or oxygen enriched air in the Claus burner, the owner or operator shall use Equation 10 of this section and the hourly emission limits determined in paragraph (a)(5)(v) or (a)(6)(v) of this section in-place of the pollutant concentration to determine the flow weighted average hourly emission limit for each hour. The allowable emission limit shall be calculated as the arithmetic average of 12 contiguous 1-hour averages (*i.e.,* the rolling 12-hour average).

(b) * * *

(2) All 12-hour periods during which the average concentration of reduced sulfur compounds (as SO_2) as measured by the reduced sulfur compounds continuous monitoring system required under paragraph (a)(2) or (3) of this section exceeds the applicable emission limit; or

(3) All 12-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under paragraph (a)(4) of this section exceeds the applicable emission limit (dry basis, 0 percent excess air).

■ 9. Section 60.107a is amended by revising paragraphs (a)(1)(i) and (ii), (b)(1)(iv), the first sentence of paragraph (b)(3)(iii), (d)(3), (e)(1) introductory text, (e)(1)(ii), (e)(2) introductory text, (e)(2)(ii), (e)(2)(vi)(C), (e)(3), (f)(1)(ii), and (h)(5) to read as follows:

§ 60.107a Monitoring of emissions and operations for fuel gas combustion devices and flares.

(a) * * *

(1) * * *

(i) The owner or operator shall install, operate, and maintain each SO_2 monitor according to Performance Specification 2 of appendix B to this part. The span value for the SO_2 monitor is 50 ppmv SO_2.

(ii) The owner or operator shall conduct performance evaluations for the SO_2 monitor according to the requirements of § 60.13(c) and Performance Specification 2 of appendix B to this part. The owner or operator shall use Methods 6, 6A, or 6C of appendix A–4 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A–4 to this part. Samples taken by Method 6 of appendix A–4 to this part shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppmv, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

* * * * *

(b) * * *

(1) * * *

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppmv H_2S. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes (''length-of-stain tube'' type measurement) following the ''Gas Processors Association Standard 2377–86 (incorporated by reference—see § 60.17), using tubes with a maximum span between 10 and 40 ppmv inclusive when $1 \leq N \leq 10$, where N = number of pump strokes, to test the applicant fuel gas stream for H_2S; and

* * * * *

(3) * * *

(iii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application and the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin H_2S monitoring using daily stain sampling to demonstrate compliance using length-of-stain tubes with a maximum span between 200 and 400 ppmv inclusive when $1 \leq N \leq 5$, where N = number of pump strokes. * * *

* * * * *

(d) * * *

(3) As an alternative to the requirements in paragraph (d)(2) of this section, the owner or operator of a gas-fired process heater shall install, operate and maintain a gas composition analyzer and determine the average F factor of the fuel gas using the factors in Table 1 of this subpart and Equation 13 of this section. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

$$F_d = \frac{1{,}000{,}000 \times \sum (X_i \times MEV_i)}{\sum (X_i \times MHC_i)} \qquad \text{(Eq. 13)}$$

Where:

F_d = F factor on dry basis at 0% excess air, dscf/MMBtu.

X_i = mole or volume fraction of each component in the fuel gas.

MEV_i = molar exhaust volume, dry standard cubic feet per mole (dscf/mol).

MHC_i = molar heat content, Btu per mole (Btu/mol).

1,000,000 = unit conversion, Btu per MMBtu.

* * * * *

(e) * * *

(1) *Total reduced sulfur monitoring requirements.* The owner or operator shall install, operate, calibrate and maintain an instrument or instruments for continuously monitoring and recording the concentration of total reduced sulfur in gas discharged to the flare.

* * * * *

(ii) The owner or operator shall conduct performance evaluations of each total reduced sulfur monitor according to the requirements in § 60.13(c) and Performance Specification 5 of appendix B to this part. The owner or operator of each total reduced sulfur monitor shall use EPA Method 15A of appendix A–5 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981 (incorporated by reference-see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to this part. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of appendix B to this part (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.

* * * * *

(2) *H_2S monitoring requirements.* The owner or operator shall install, operate, calibrate, and maintain an instrument or instruments for continuously monitoring and recording the concentration of H_2S in gas discharged to the flare according to the requirements in paragraphs (e)(2)(i) through (iii) of this section and shall collect and analyze samples of the gas and calculate total sulfur concentrations as specified in paragraphs (e)(2)(iv) through (ix) of this section.

* * * * *

(ii) The owner or operator shall conduct performance evaluations of each H_2S monitor according to the requirements in § 60.13(c) and Performance Specification 7 of appendix B to this part. The owner or operator shall use EPA Method 11, 15 or 15A of appendix A–5 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to this part. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of appendix B to this part (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.

* * * * *

(vi) * * *

(C) Determine the acceptable range for subsequent weekly samples based on the 95-percent confidence interval for the distribution of daily ratios based on the 10 individual daily ratios using Equation 14 of this section.

$$AR = Ratio_{Avg} \pm 2.262 \times SDev \qquad \text{(Eq. 14)}$$

Where:

AR = Acceptable range of subsequent ratio determinations, unitless.

$Ratio_{Avg}$ = 10-day average total sulfur-to-H_2S concentration ratio, unitless.

2.262 = t-distribution statistic for 95-percent 2-sided confidence interval for 10 samples (9 degrees of freedom).

SDev = Standard deviation of the 10 daily average total sulfur-to-H_2S concentration ratios used to develop the 10-day average total sulfur-to-H_2S concentration ratio, unitless.

* * * * *

(3) *SO_2 monitoring requirements.* The owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of SO_2 from a process heater or other fuel gas combustion device that is combusting gas representative of the fuel gas in the flare gas line according to the requirements in paragraph (a)(1) of this section, determine the F factor of the fuel gas at least daily according to the requirements in paragraphs (d)(2) through (4) of this section, determine the higher heating value of the fuel gas at least daily according to the requirements in paragraph (d)(7) of this section, and calculate the total sulfur content (as SO_2) in the fuel gas using Equation 15 of this section.

$$TS_{FG} = C_{SO_2} \times F_d \times HHV_{FG} \qquad \text{(Eq. 15)}$$

Where:

TS_{FG} = Total sulfur concentration, as SO_2, in the fuel gas, ppmv.

C_{SO2} = Concentration of SO_2 in the exhaust gas, ppmv (dry basis at 0-percent excess air).

F_d = F factor gas on dry basis at 0-percent excess air, dscf/MMBtu.

HHV_{FG} = Higher heating value of the fuel gas, MMBtu/scf.

* * * * *

(f) * * *

(1) * * *

(ii) Use a flow sensor meeting an accuracy requirement of ±20 percent of the flow rate at velocities ranging from 0.1 to 1 feet per second and an accuracy of ±5 percent of the flow rate for velocities greater than 1 feet per second.

* * * * *

(h) * * *

(5) *Daily O_2 limits for fuel gas combustion devices.* Each day during which the concentration of O_2 as measured by the O_2 continuous monitoring system required under paragraph (c)(6) or (d)(8) of this section exceeds the O_2 operating limit or operating curve determined during the most recent biennial performance test.

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 10. The authority citation for part 63 continues to read as follows:

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

Subpart A—General Provisions

■ 11. Section 63.14 is amended by:

■ a. Revising paragraph (h)(14);

■ b. Redesignating paragraphs (h)(82) through (99) as (h)(86) through (103), paragraphs (h)(77) through (81) as (h)(80) through (84), paragraphs (h)(73) through (76) as paragraphs (h)(75) through (78), and paragraphs (h)(15) through (72) as (16) through (73), respectively;

■ c. Revising newly redesignated paragraph (h)(78);

■ d. Adding paragraphs (h)(15), (74), (79), (85), (104) and (j)(2);

■ e. Redesignating paragraph (m)(3) through (21) as (m)(5) through (23), respectively, and paragraph (m)(2) as (m)(3).

■ f. Adding paragraphs (m)(2) and (4) and (n)(3); and

■ g. Revising paragraph (s)(1).

The revisions and additions read as follows:

§ 63.14 Incorporation by reference.

* * * * *

(h) * * *

(14) ASTM D1945–03 (Reapproved 2010), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, Approved January 1, 2010, IBR approved for §§ 63.670(j), 63.772(h), and 63.1282(g).

(15) ASTM D1945–14, Standard Test Method for Analysis of Natural Gas by Gas Chromatography, Approved

November 1, 2014, IBR approved for § 63.670(j).

* * * * *

(74) ASTM D6196–03 (Reapproved 2009), Standard Practice for Selection of Sorbents, Sampling, and Thermal Desorption Analysis Procedures for Volatile Organic Compounds in Air, Approved March 1, 2009, IBR approved for appendix A to this part: Method 325A and Method 325B.

* * * * *

(78) ASTM D6348–03 (Reapproved 2010), Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, including Annexes A1 through A8, Approved October 1, 2010, IBR approved for § 63.1571(a), tables 4 and 5 to subpart JJJJJ, tables 4 and 6 to subpart KKKKK, tables 1, 2, and 5 to subpart UUUUU and appendix B to subpart UUUUU.

* * * * *

(79) 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 § 63.1571(a).

* * * * *

(85) ASTM D6420–99 (Reapproved 2010), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, Approved October 1, 2010, IBR approved for § 63.670(j) and appendix A to this part: Method 325B.

* * * * *

(104) ASTM UOP539–12, Refinery Gas Analysis by GC, Copyright 2012 (to UOP), IBR approved for § 63.670(j).

* * * * *

(j) * * *

(2) BS EN 14662–4:2005, Ambient air quality standard method for the measurement of benzene concentrations—Part 4: Diffusive sampling followed by thermal desorption and gas chromatography, Published June 27, 2005, IBR approved for appendix A to this part: Method 325A and Method 325B.

* * * * *

(m) * * *

(2) EPA–454/B–08–002, Office of Air Quality Planning and Standards (OAQPS), Quality Assurance Handbook for Air Pollution Measurement Systems, Volume IV: Meteorological Measurements, Version 2.0 (Final), March 24, 2008, IBR approved for § 63.658(d) and appendix A to this part: Method 325A.

* * * * *

(4) EPA–454/R–99–005, Office of Air Quality Planning and Standards (OAQPS), Meteorological Monitoring Guidance for Regulatory Modeling Applications, February 2000, IBR approved for appendix A to this part: Method 325A.

* * * * *

(n) * * *

(3) ISO 16017–2:2003(E): Indoor, ambient and workplace air—sampling and analysis of volatile organic compounds by sorbent tube/thermal desorption/capillary gas chromatography—Part 2: Diffusive sampling, May 15, 2003, IBR approved for appendix A to this part: Method 325A and Method 325B.

* * * * *

(s) * * *

(1) ''Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources,'' Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, January 31, 2003, IBR approved for §§ 63.654(c) and (g), 63.655(i), and 63.11920.

* * * * *

Subpart Y—National Emission Standards for Marine Tank Vessel Loading Operations

■ 12. Section 63.560 is amended by revising paragraph (a)(4) to read as follows:

§ 63.560 Applicability and designation of affected source.

(a) * * *

(4) Existing sources with emissions less than 10 and 25 tons must meet the submerged fill standards of 46 CFR 153.282.

* * * * *

Subpart CC—National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

■ 13. Section 63.640 is amended by:

■ a. Revising paragraphs (a) introductory text and (c) introductory text;

■ c. Adding paragraph (c)(9);

■ d. Revising paragraphs (d)(5), (h), (k)(1), (l) introductory text, (l)(2) introductory text, (l)(2)(i), (l)(3) introductory text, (m) introductory text, (n) introductory text, (n)(1) through (5), (n)(8) introductory text, and (n)(8)(ii);

■ e. Adding paragraphs (n)(8)(vii) and (viii);

■ f. Revising paragraph (n)(9)(i);

■ g. Adding paragraph (n)(10);

■ h. Revising paragraph (o)(2)(i) introductory text;

■ i. Adding paragraph (o)(2)(i)(D);

■ j. Revising paragraph (o)(2)(ii) introductory text; and

■ k. Adding paragraphs (o)(2)(ii)(C) and (s).

The revisions and additions read as follows:

§ 63.640 Applicability and designation of affected source.

(a) This subpart applies to petroleum refining process units and to related emissions points that are specified in paragraphs (c)(1) through (9) of this section that are located at a plant site and that meet the criteria in paragraphs (a)(1) and (2) of this section:

* * * * *

(c) For the purposes of this subpart, the affected source shall comprise all emissions points, in combination, listed in paragraphs (c)(1) through (9) of this section that are located at a single refinery plant site.

* * * * *

(9) All releases associated with the decoking operations of a delayed coking unit, as defined in this subpart.

(d) * * *

(5) Emission points routed to a fuel gas system, as defined in § 63.641, provided that on and after January 30, 2019, any flares receiving gas from that fuel gas system are subject to § 63.670. No other testing, monitoring, recordkeeping, or reporting is required for refinery fuel gas systems or emission points routed to refinery fuel gas systems.

* * * * *

(h) Sources subject to this subpart are required to achieve compliance on or before the dates specified in table 11 of this subpart, except as provided in paragraphs (h)(1) through (3) of this section.

(1) Marine tank vessels at existing sources shall be in compliance with this subpart, except for §§ 63.657 through 63.660, no later than August 18, 1999, unless the vessels are included in an emissions average to generate emission credits. Marine tank vessels used to generate credits in an emissions average shall be in compliance with this subpart no later than August 18, 1998, unless an extension has been granted by the Administrator as provided in § 63.6(i).

(2) Existing Group 1 floating roof storage vessels meeting the applicability criteria in item 1 of the definition of Group 1 storage vessel shall be in compliance with § 63.646 at the first degassing and cleaning activity after August 18, 1998, or August 18, 2005, whichever is first.

(3) An owner or operator may elect to comply with the provisions of § 63.648(c) through (i) as an alternative to the provisions of § 63.648(a) and (b). In such cases, the owner or operator shall comply no later than the dates specified in paragraphs (h)(3)(i) through (iii) of this section.

(i) Phase I (see table 2 of this subpart), beginning on August 18, 1998;

(ii) Phase II (see table 2 of this subpart), beginning no later than August 18, 1999; and

(iii) Phase III (see table 2 of this subpart), beginning no later than February 18, 2001.

* * * * *

(k) * * *

(1) The reconstructed source, addition, or change shall be in compliance with the new source requirements in item (1), (2), or (3) of table 11 of this subpart, as applicable, upon initial startup of the reconstructed source or by August 18, 1995, whichever is later; and

* * * * *

(l) If an additional petroleum refining process unit is added to a plant site or if a miscellaneous process vent, storage vessel, gasoline loading rack, marine tank vessel loading operation, heat exchange system, or decoking operation that meets the criteria in paragraphs (c)(1) through (9) of this section is added to an existing petroleum refinery or if another deliberate operational process change creating an additional Group 1 emissions point(s) (as defined in § 63.641) is made to an existing petroleum refining process unit, and if the addition or process change is not subject to the new source requirements as determined according to paragraph (i) or (j) of this section, the requirements in paragraphs (l)(1) through (4) of this section shall apply. Examples of process changes include, but are not limited to, changes in production capacity, or feed or raw material where the change requires construction or physical alteration of the existing equipment or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph (l) and paragraph (m) of this section, process changes do not include: Process upsets, unintentional temporary process changes, and changes that are within the equipment configuration and operating conditions documented in the Notification of Compliance Status report required by § 63.655(f).

* * * * *

(2) The added emission point(s) and any emission point(s) within the added or changed petroleum refining process unit shall be in compliance with the applicable requirements in item (4) of table 11 of this subpart by the dates specified in paragraph (l)(2)(i) or (ii) of this section.

(i) If a petroleum refining process unit is added to a plant site or an emission point(s) is added to any existing petroleum refining process unit, the added emission point(s) shall be in compliance upon initial startup of any added petroleum refining process unit or emission point(s) or by the applicable compliance date in item (4) of table 11 of this subpart, whichever is later.

* * * * *

(3) The owner or operator of a petroleum refining process unit or of a storage vessel, miscellaneous process vent, wastewater stream, gasoline loading rack, marine tank vessel loading operation, heat exchange system, or decoking operation meeting the criteria in paragraphs (c)(1) through (9) of this section that is added to a plant site and is subject to the requirements for existing sources shall comply with the reporting and recordkeeping requirements that are applicable to existing sources including, but not limited to, the reports listed in paragraphs (l)(3)(i) through (vii) of this section. A process change to an existing petroleum refining process unit shall be subject to the reporting requirements for existing sources including, but not limited to, the reports listed in paragraphs (l)(3)(i) through (vii) of this section. The applicable reports include, but are not limited to:

* * * * *

(m) If a change that does not meet the criteria in paragraph (l) of this section is made to a petroleum refining process unit subject to this subpart, and the change causes a Group 2 emission point to become a Group 1 emission point (as defined in § 63.641), then the owner or operator shall comply with the applicable requirements of this subpart for existing sources, as specified in item (4) of table 11 of this subpart, for the Group 1 emission point as expeditiously as practicable, but in no event later than 3 years after the emission point becomes Group 1.

* * * * *

(n) Overlap of this subpart with other regulations for storage vessels. As applicable, paragraphs (n)(1), (3), (4), (6), and (7) of this section apply for Group 2 storage vessels and paragraphs (n)(2) and (5) of this section apply for Group 1 storage vessels.

(1) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to the provisions of 40 CFR part 60, subpart Kb, is required to comply only with the requirements of 40 CFR part 60, subpart Kb, except as provided in paragraph (n)(8) of this section. After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to the provisions of 40 CFR part 61, subpart Y, is required to comply only with the requirements of 40 CFR part 61, subpart Y, except as provided in paragraph (n)(10) of this section.

(2) After the compliance dates specified in paragraph (h) of this section, a Group 1 storage vessel that is also subject to 40 CFR part 60, subpart Kb, is required to comply only with either 40 CFR part 60, subpart Kb, except as provided in paragraph (n)(8) of this section or this subpart. After the compliance dates specified in paragraph (h) of this section, a Group 1 storage vessel that is also subject to 40 CFR part 61, subpart Y, is required to comply only with either 40 CFR part 61, subpart Y, except as provided in paragraph (n)(10) of this section or this subpart.

(3) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is part of a new source and is subject to 40 CFR 60.110b, but is not required to apply controls by 40 CFR 60.110b or 60.112b, is required to comply only with this subpart.

(4) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is part of a new source and is subject to 40 CFR 61.270, but is not required to apply controls by 40 CFR 61.271, is required to comply only with this subpart.

(5) After the compliance dates specified in paragraph (h) of this section, a Group 1 storage vessel that is also subject to the provisions of 40 CFR part 60, subpart K or Ka, is required to only comply with the provisions of this subpart.

* * * * *

(8) Storage vessels described by paragraph (n)(1) of this section are to comply with 40 CFR part 60, subpart Kb, except as provided in paragraphs (n)(8)(i) through (vi) of this section. Storage vessels described by paragraph (n)(2) electing to comply with part 60, subpart Kb of this chapter shall comply with subpart Kb except as provided in paragraphs (n)(8)(i) through (viii) of this section.

* * * * *

(ii) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in § 60.113b(b) of this chapter or to inspect the vessel to determine compliance with

§ 60.113b(a) of this chapter because the roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either § 63.120(b)(7)(i) or (ii) of subpart G (only up to the compliance date specified in paragraph (h) of this section for compliance with § 63.660, as applicable) or either § 63.1063(c)(2)(iv)(A) or (B) of subpart WW.

* * * * *

(vii) To be in compliance with § 60.112b(a)(1)(iv) or (a)(2)(ii) of this chapter, guidepoles in floating roof storage vessels must be equipped with covers and/or controls (*e.g.,* pole float system, pole sleeve system, internal sleeve system or flexible enclosure system) as appropriate to comply with the ''no visible gap'' requirement.

(viii) If a flare is used as a control device for a storage vessel, on and after January 30, 2019, the owner or operator must meet the requirements of § 63.670 instead of the requirements referenced from part 60, subpart Kb of this chapter for that flare.

(9) * * *

(i) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in § 60.113a(a)(1) of this chapter because the floating roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either § 63.120(b)(7)(i) or (ii) of subpart G (only up to the compliance date specified in paragraph (h) of this section for compliance with § 63.660, as applicable) or either § 63.1063(c)(2)(iv)(A) or (B) of subpart WW.

* * * * *

(10) Storage vessels described by paragraph (n)(1) of this section are to comply with 40 CFR part 61, subpart Y, except as provided in paragraphs (n)(10)(i) through (vi) of this section. Storage vessels described by paragraph (n)(2) electing to comply with 40 CFR part 61, subpart Y, shall comply with subpart Y except as provided for in paragraphs (n)(10)(i) through (viii) of this section.

(i) Storage vessels that are to comply with § 61.271(b) of this chapter are exempt from the secondary seal requirements of § 61.271(b)(2)(ii) of this chapter during the gap measurements for the primary seal required by § 61.272(b) of this chapter.

(ii) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in § 61.272(b) of this chapter or to inspect the vessel to determine compliance with § 61.272(a) of this chapter because the roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either § 63.120(b)(7)(i) or (ii) of subpart G (only up to the compliance date specified in paragraph (h) of this section for compliance with § 63.660, as applicable) or either § 63.1063(c)(2)(iv)(A) or (B) of subpart WW.

(iii) If a failure is detected during the inspections required by § 61.272(a)(2) of this chapter or during the seal gap measurements required by § 61.272(b)(1) of this chapter, and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to two extensions of up to 30 additional calendar days each. The owner or operator is not required to provide a request for the extension to the Administrator.

(iv) If an extension is utilized in accordance with paragraph (n)(10)(iii) of this section, the owner or operator shall, in the next periodic report, identify the vessel, provide the information listed in § 61.272(a)(2) or (b)(4)(iii) of this chapter, and describe the nature and date of the repair made or provide the date the storage vessel was emptied.

(v) Owners and operators of storage vessels complying with 40 CFR part 61, subpart Y, may submit the inspection reports required by § 61.275(a), (b)(1), and (d) of this chapter as part of the periodic reports required by this subpart, rather than within the 60-day period specified in § 61.275(a), (b)(1), and (d) of this chapter.

(vi) The reports of rim seal inspections specified in § 61.275(d) of this chapter are not required if none of the measured gaps or calculated gap areas exceed the limitations specified in § 61.272(b)(4) of this chapter. Documentation of the inspections shall be recorded as specified in § 61.276(a) of this chapter.

(vii) To be in compliance with § 61.271(a)(6) or (b)(3) of this chapter, guidepoles in floating roof storage vessels must be equipped with covers and/or controls (*e.g.,* pole float system, pole sleeve system, internal sleeve system or flexible enclosure system) as appropriate to comply with the ''no visible gap'' requirement.

(viii) If a flare is used as a control device for a storage vessel, on and after January 30, 2019, the owner or operator must meet the requirements of § 63.670 instead of the requirements referenced from part 61, subpart Y of this chapter for that flare.

(o) * * *

(2) * * *

(i) Comply with paragraphs (o)(2)(i)(A) through (D) of this section.

* * * * *

(D) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of § 63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of 40 CFR part 61, subpart FF, and subpart G of this part, or the requirements of § 63.670.

(ii) Comply with paragraphs (o)(2)(ii)(A) through (C) of this section.

* * * * *

(C) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of § 63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of 40 CFR part 61, subpart FF, and subpart G of this part, or the requirements of § 63.670.

* * * * *

(s) Overlap of this subpart with other regulation for flares. On January 30, 2019, flares that are subject to the provisions of 40 CFR 60.18 or 63.11 and subject to this subpart are required to comply only with the provisions specified in this subpart. Prior to January 30, 2019, flares that are subject to the provisions of 40 CFR 60.18 or 63.11 and elect to comply with the requirements in §§ 63.670 and 63.671 are required to comply only with the provisions specified in this subpart.

■ 14. Section 63.641 is amended by:

■ a. Adding, in alphabetical order, definitions of ''Assist air,'' ''Assist steam,'' ''Center steam,'' ''Closed blowdown system,'' ''Combustion zone,'' ''Combustion zone gas,'' ''Decoking operations,'' ''Delayed coking unit,'' ''Flare,'' ''Flare purge gas,'' ''Flare supplemental gas,'' ''Flare sweep gas,'' ''Flare vent gas,'' ''Flexible enclosure device,'' ''Force majeure event,'' ''Lower steam,'' ''Net heating value,'' ''Perimeter assist air,'' ''Pilot gas,'' ''Premix assist air,'' ''Regulated material,'' ''Thermal expansion relief valve,'' ''Total steam,'' and ''Upper steam''; and

■ b. Revising the definitions of ''Delayed coker vent,'' ''Emission point,'' ''Group 1 storage vessel,'' ''Miscellaneous process vent,'' ''Periodically discharged,'' and ''Reference control technology for storage vessels.''

The revisions and additions read as follows:

§ 63.641 Definitions.

* * * * *

Assist air means all air that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. *Assist air* includes premix assist air and perimeter assist air. *Assist air* does not include the surrounding ambient air.

Assist steam means all steam that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. *Assist steam* includes, but is not necessarily limited to, center steam, lower steam and upper steam.

* * * * *

Center steam means the portion of assist steam introduced into the stack of a flare to reduce burnback.

Closed blowdown system means a system used for depressuring process vessels that is not open to the atmosphere and is configured of piping, ductwork, connections, accumulators/knockout drums, and, if necessary, flow inducing devices that transport gas or vapor from process vessel to a control device or back into the process.

* * * * *

Combustion zone means the area of the flare flame where the combustion zone gas combines for combustion.

Combustion zone gas means all gases and vapors found just after a flare tip. This gas includes all flare vent gas, total steam, and premix air.

* * * * *

Decoking operations means the sequence of steps conducted at the end of the delayed coking unit's cooling cycle to open the coke drum to the atmosphere in order to remove coke from the coke drum. *Decoking operations* begin at the end of the cooling cycle when steam released from the coke drum is no longer discharged via the unit's blowdown system but instead is vented directly to the atmosphere. *Decoking operations* include atmospheric depressuring (venting), deheading, draining, and decoking (coke cutting).

Delayed coker vent means a miscellaneous process vent that contains uncondensed vapors from the delayed coking unit's blowdown system. Venting from the *delayed coker vent* is typically intermittent in nature, and occurs primarily during the cooling cycle of a delayed coking unit coke drum when vapor from the coke drums cannot be sent to the fractionator column for product recovery. The emissions from the decoking operations, which include direct atmospheric venting, deheading, draining, or decoking (coke cutting), are not considered to be *delayed coker vents*.

Delayed coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A *delayed coking unit* includes, but is not limited to, all of the coke drums associated with a single fractionator; the fractionator, including the bottoms receiver and the overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; and the coke drum blowdown recovery compressor system.

* * * * *

Emission point means an individual miscellaneous process vent, storage vessel, wastewater stream, equipment leak, decoking operation or heat exchange system associated with a petroleum refining process unit; an individual storage vessel or equipment leak associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial Classification code 2911; a gasoline loading rack classified under Standard Industrial Classification code 2911; or a marine tank vessel loading operation located at a petroleum refinery.

* * * * *

Flare means a combustion device lacking an enclosed combustion chamber that uses an uncontrolled volume of ambient air to burn gases. For the purposes of this rule, the definition of *flare* includes, but is not necessarily limited to, air-assisted flares, steam-assisted flares and non-assisted flares.

Flare purge gas means gas introduced between a flare header's water seal and the flare tip to prevent oxygen infiltration (backflow) into the flare tip. For a flare with no water seal, the function of *flare purge gas* is performed by flare sweep gas and, therefore, by definition, such a flare has no *flare purge gas*.

Flare supplemental gas means all gas introduced to the flare in order to improve the combustible characteristics of combustion zone gas.

Flare sweep gas means, for a flare with a flare gas recovery system, the gas intentionally introduced into the flare header system to maintain a constant flow of gas through the flare header in order to prevent oxygen buildup in the flare header; *flare sweep gas* in these flares is introduced prior to and recovered by the flare gas recovery system. For a flare without a flare gas recovery system, *flare sweep gas* means the gas intentionally introduced into the flare header system to maintain a constant flow of gas through the flare header and out the flare tip in order to prevent oxygen buildup in the flare header and to prevent oxygen infiltration (backflow) into the flare tip.

Flare vent gas means all gas found just prior to the flare tip. This gas includes all flare waste gas (*i.e.*, gas from facility operations that is directed to a flare for the purpose of disposing of the gas), that portion of flare sweep gas that is not recovered, flare purge gas and flare supplemental gas, but does not include pilot gas, total steam or assist air.

Flexible enclosure device means a seal made of an elastomeric fabric (or other material) which completely encloses a slotted guidepole or ladder and eliminates the vapor emission pathway from inside the storage vessel through the guidepole slots or ladder slots to the outside air.

* * * * *

Force majeure event means a release of HAP, either directly to the atmosphere from a relief valve or discharged via a flare, that is demonstrated to the satisfaction of the Administrator to result from an event beyond the refinery owner or operator's control, such as natural disasters; acts of war or terrorism; loss of a utility external to the refinery (*e.g.,* external power curtailment), excluding power curtailment due to an interruptible service agreement; and fire or explosion originating at a near or adjoining facility outside of the refinery owner or operator's control that impacts the refinery's ability to operate.

* * * * *

Group 1 storage vessel means:

(1) Prior to February 1, 2016:

(i) A storage vessel at an existing source that has a design capacity greater than or equal to 177 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 10.4 kilopascals and stored-liquid annual average true vapor pressure greater than or equal to 8.3 kilopascals and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP;

(ii) A storage vessel at a new source that has a design storage capacity greater than or equal to 151 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 3.4 kilopascals and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP; or

(iii) A storage vessel at a new source that has a design storage capacity greater than or equal to 76 cubic meters and less than 151 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 77 kilopascals and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP.

(2) On and after February 1, 2016:

(i) A storage vessel at an existing source that has a design capacity greater than or equal to 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 5.2 kilopascals (0.75 pounds per square inch) and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP;

(ii) A storage vessel at an existing source that has a design storage capacity greater than or equal to 76 cubic meters (20,000 gallons) and less than 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 13.1 kilopascals (1.9 pounds per square inch) and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP;

(iii) A storage vessel at a new source that has a design storage capacity greater than or equal to 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 3.4 kilopascals (0.5 pounds per square inch) and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP; or

(iv) A storage vessel at a new source that has a design storage capacity greater than or equal to 76 cubic meters (20,000 gallons) and less than 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 13.1 kilopascals (1.9 pounds per square inch) and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP.

* * * * *

Lower steam means the portion of assist steam piped to an exterior annular ring near the lower part of a flare tip, which then flows through tubes to the flare tip, and ultimately exits the tubes at the flare tip.

* * * * *

Miscellaneous process vent means a gas stream containing greater than 20 parts per million by volume organic HAP that is continuously or periodically discharged from a petroleum refining process unit meeting the criteria specified in § 63.640(a). *Miscellaneous process vents* include gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device prior to control or discharge to the atmosphere. *Miscellaneous process vents* include vent streams from: Caustic wash accumulators, distillation tower condensers/accumulators, flash/knockout drums, reactor vessels, scrubber overheads, stripper overheads, vacuum pumps, steam ejectors, hot wells, high point bleeds, wash tower overheads, water wash accumulators, blowdown condensers/accumulators, and delayed coker vents. *Miscellaneous process vents* do not include:

(1) Gaseous streams routed to a fuel gas system, provided that on and after January 30, 2019, any flares receiving gas from the fuel gas system are in compliance with § 63.670;

(2) Pressure relief device discharges;

(3) Leaks from equipment regulated under § 63.648;

(4) [Reserved]

(5) In situ sampling systems (onstream analyzers) until January 30, 2019. After this date, these sampling systems will be included in the definition of miscellaneous process vents;

(6) Catalytic cracking unit catalyst regeneration vents;

(7) Catalytic reformer regeneration vents;

(8) Sulfur plant vents;

(9) Vents from control devices such as scrubbers, boilers, incinerators, and electrostatic precipitators applied to catalytic cracking unit catalyst regeneration vents, catalytic reformer regeneration vents, and sulfur plant vents;

(10) Vents from any stripping operations applied to comply with the wastewater provisions of this subpart, subpart G of this part, or 40 CFR part 61, subpart FF;

(11) Emissions associated with delayed coking unit decoking operations;

(12) Vents from storage vessels;

(13) Emissions from wastewater collection and conveyance systems including, but not limited to, wastewater drains, sewer vents, and sump drains; and

(14) Hydrogen production plant vents through which carbon dioxide is removed from process streams or through which steam condensate produced or treated within the hydrogen plant is degassed or deaerated.

Net heating value means the energy released as heat when a compound undergoes complete combustion with oxygen to form gaseous carbon dioxide and gaseous water (also referred to as lower heating value).

* * * * *

Perimeter assist air means the portion of assist air introduced at the perimeter of the flare tip or above the flare tip. *Perimeter assist air* includes air intentionally entrained in lower and upper steam. *Perimeter assist air* includes all assist air except premix assist air.

Periodically discharged means discharges that are intermittent and associated with routine operations, maintenance activities, startups, shutdowns, malfunctions, or process upsets.

* * * * *

Pilot gas means gas introduced into a flare tip that provides a flame to ignite the flare vent gas.

* * * * *

Premix assist air means the portion of assist air that is introduced to the flare vent gas, whether injected or induced, prior to the flare tip. Premix assist air also includes any air intentionally entrained in center steam.

* * * * *

Reference control technology for storage vessels means either:

(1) For Group 1 storage vessels complying with § 63.660:

(i) An internal floating roof, including an external floating roof converted to an internal floating roof, meeting the specifications of § 63.1063(a)(1)(i) and (b);

(ii) An external floating roof meeting the specifications of § 63.1063(a)(1)(ii), (a)(2), and (b); or

(iii) [Reserved]

(iv) A closed-vent system to a control device that reduces organic HAP emissions by 95 percent, or to an outlet concentration of 20 parts per million by volume (ppmv).

(v) For purposes of emissions averaging, these four technologies are considered equivalent.

(2) For all other storage vessels:

(i) An internal floating roof meeting the specifications of § 63.119(b) of subpart G except for § 63.119(b)(5) and (6);

(ii) An external floating roof meeting the specifications of § 63.119(c) of subpart G except for § 63.119(c)(2);

(iii) An external floating roof converted to an internal floating roof meeting the specifications of § 63.119(d) of subpart G except for § 63.119(d)(2); or

(iv) A closed-vent system to a control device that reduces organic HAP emissions by 95 percent, or to an outlet concentration of 20 parts per million by volume.

(v) For purposes of emissions averaging, these four technologies are considered equivalent.

* * * * *

Regulated material means any stream associated with emission sources listed in § 63.640(c) required to meet control requirements under this subpart as well as any stream for which this subpart or a cross-referencing subpart specifies that the requirements for flare control devices in § 63.670 must be met.

* * * * *

Thermal expansion relief valve means a pressure relief valve designed to protect equipment from excess pressure due to thermal expansion of blocked liquid-filled equipment or piping due to ambient heating or heat from a heat tracing system. Pressure relief valves designed to protect equipment from excess pressure due to blockage against a pump or compressor or due to fire contingency are not thermal expansion relief valves.

* * * * *

Total steam means the total of all steam that is supplied to a flare and includes, but is not limited to, lower steam, center steam and upper steam.

Upper steam means the portion of assist steam introduced via nozzles located on the exterior perimeter of the upper end of the flare tip.

* * * * *

■ 15. Section 63.642 is amended by:
■ a. Adding paragraph (b);
■ b. Revising paragraphs (d)(3), (e), (i), (k) introductory text, (k)(1), (l) introductory text, and (l)(2); and
■ c. Adding paragraph (n).

The revisions and additions read as follows:

§ 63.642 General standards.

* * * * *

(b) The emission standards set forth in this subpart shall apply at all times.

* * * * *

(d) * * *

(3) Performance tests shall be conducted according to the provisions of § 63.7(e) except that performance tests shall be conducted at maximum representative operating capacity for the process. During the performance test, an owner or operator shall operate the control device at either maximum or minimum representative operating conditions for monitored control device parameters, whichever results in lower emission reduction. An owner or operator shall not conduct a performance test during startup, shutdown, periods when the control device is bypassed or periods when the process, monitoring equipment or control device is not operating properly. The owner/operator may not conduct performance tests during periods of malfunction. The owner or operator must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that the test was conducted at maximum representative operating capacity. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

* * * * *

(e) All applicable records shall be maintained as specified in § 63.655(i).

* * * * *

(i) The owner or operator of an existing source shall demonstrate compliance with the emission standard in paragraph (g) of this section by following the procedures specified in paragraph (k) of this section for all emission points, or by following the emissions averaging compliance approach specified in paragraph (l) of this section for specified emission points and the procedures specified in paragraph (k)(1) of this section.

* * * * *

(k) The owner or operator of an existing source may comply, and the owner or operator of a new source shall comply, with the applicable provisions in §§ 63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as specified in § 63.640(h).

(1) The owner or operator using this compliance approach shall also comply with the requirements of §§ 63.648 and/or 63.649, 63.654, 63.655, 63.657, 63.658, 63.670 and 63.671, as applicable.

* * * * *

(l) The owner or operator of an existing source may elect to control some of the emission points within the source to different levels than specified under §§ 63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable according to § 63.640(h), by using an emissions averaging compliance approach as long as the overall emissions for the source do not exceed the emission level specified in paragraph (g) of this section. The owner or operator using emissions averaging shall meet the requirements in paragraphs (l)(1) and (2) of this section.

* * * * *

(2) Comply with the requirements of §§ 63.648 and/or 63.649, 63.654, 63.652, 63.653, 63.655, 63.657, 63.658, 63.670 and 63.671, as applicable.

* * * * *

(n) At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

■ 16. Section 63.643 is amended by revising paragraphs (a) introductory text and (a)(1) and adding paragraph (c) to read as follows:

§ 63.643 Miscellaneous process vent provisions.

(a) The owner or operator of a Group 1 miscellaneous process vent as defined in § 63.641 shall comply with the requirements of either paragraph (a)(1) or (2) of this section or, if applicable, paragraph (c) of this section. The owner or operator of a miscellaneous process vent that meets the conditions in paragraph (c) of this section is only required to comply with the requirements of paragraph (c) of this section and § 63.655(g)(13) and (i)(12) for that vent.

(1) Reduce emissions of organic HAP's using a flare. On and after January 30, 2019, the flare shall meet the requirements of § 63.670. Prior to January 30, 2019, the flare shall meet the requirements of § 63.11(b) of subpart A or the requirements of § 63.670.

* * * * *

(c) An owner or operator may designate a process vent as a maintenance vent if the vent is only used as a result of startup, shutdown, maintenance, or inspection of equipment where equipment is emptied, depressurized, degassed or placed into service. The owner of operator does not need to designate a maintenance vent as a Group 1 or Group 2 miscellaneous process vent. The owner or operator must comply with the applicable requirements in paragraphs (c)(1) through (3) of this section for each maintenance vent.

(1) Prior to venting to the atmosphere, process liquids are removed from the equipment as much as practical and the equipment is depressured to a control device, fuel gas system, or back to the process until one of the following conditions, as applicable, is met.

(i) The vapor in the equipment served by the maintenance vent has a lower explosive limit (LEL) of less than 10 percent.

(ii) If there is no ability to measure the LEL of the vapor in the equipment based on the design of the equipment, the pressure in the equipment served by the maintenance vent is reduced to 5 psig or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the LEL of the vapors in the maintenance vent (or inside the equipment if the maintenance is a hatch or similar type of opening) equipment is less than 10 percent.

(iii) The equipment served by the maintenance vent contains less than 72 pounds of VOC.

(iv) If the maintenance vent is associated with equipment containing pyrophoric catalyst (*e.g.*, hydrotreaters and hydrocrackers) at refineries that do not have a pure hydrogen supply, the LEL of the vapor in the equipment must be less than 20 percent, except for one event per year not to exceed 35 percent.

(2) Except for maintenance vents complying with the alternative in paragraph (c)(1)(iii) of this section, the owner or operator must determine the LEL or, if applicable, equipment pressure using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications.

(3) For maintenance vents complying with the alternative in paragraph (c)(1)(iii) of this section, the owner or operator shall determine mass of VOC in the equipment served by the maintenance vent based on the equipment size and contents after considering any contents drained or purged from the equipment. Equipment size may be determined from equipment design specifications. Equipment contents may be determined using process knowledge.

■ 17. Section 63.644 is amended by revising paragraphs (a) introductory text, (a)(2), and (c) to read as follows:

§ 63.644 Monitoring provisions for miscellaneous process vents.

(a) Except as provided in paragraph (b) of this section, each owner or operator of a Group 1 miscellaneous process vent that uses a combustion device to comply with the requirements in § 63.643(a) shall install the monitoring equipment specified in paragraph (a)(1), (2), (3), or (4) of this section, depending on the type of combustion device used. All monitoring equipment shall be installed, calibrated, maintained, and operated according to manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately and, except for CPMS installed for pilot flame monitoring, must meet the applicable minimum accuracy, calibration and quality control requirements specified in table 13 of this subpart.

* * * * *

(2) Where a flare is used prior to January 30, 2019, a device (including but not limited to a thermocouple, an ultraviolet beam sensor, or an infrared sensor) capable of continuously detecting the presence of a pilot flame is required, or the requirements of § 63.670 shall be met. Where a flare is used on and after January 30, 2019, the requirements of § 63.670 shall be met.

* * * * *

(c) The owner or operator of a Group 1 miscellaneous process vent using a vent system that contains bypass lines that could divert a vent stream away from the control device used to comply with paragraph (a) of this section either directly to the atmosphere or to a control device that does not comply with the requirements in § 63.643(a) shall comply with either paragraph (c)(1) or (2) of this section. Use of the bypass at any time to divert a Group 1 miscellaneous process vent stream to the atmosphere or to a control device that does not comply with the requirements in § 63.643(a) is an emissions standards violation. Equipment such as low leg drains and equipment subject to § 63.648 are not subject to this paragraph (c).

(1) Install, calibrate and maintain a flow indicator that determines whether a vent stream flow is present at least once every hour. A manual block valve equipped with a valve position indicator may be used in lieu of a flow indicator, as long as the valve position indicator is monitored continuously. Records shall be generated as specified in § 63.655(h) and (i). The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere; or

(2) Secure the bypass line valve in the non-diverting position with a car-seal or a lock-and-key type configuration. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the non-diverting position and that the vent stream is not diverted through the bypass line.

* * * * *

■ 18. Section 63.645 is amended by revising paragraphs (e)(1) and (f)(2) to read as follows:

§ 63.645 Test methods and procedures for miscellaneous process vents.

* * * * *

(e) * * *

(1) Methods 1 or 1A of 40 CFR part 60, appendix A–1, as appropriate, shall be used for selection of the sampling site. For vents smaller than 0.10 meter in diameter, sample at the center of the vent.

* * * * *

(f) * * *

(2) The gas volumetric flow rate shall be determined using Methods 2, 2A, 2C, 2D, or 2F of 40 CFR part 60, appendix A–1 or Method 2G of 40 CFR part 60, appendix A–2, as appropriate.

* * * * *

■ 19. Section 63.646 is amended by adding introductory text and revising paragraph (b)(2) to read as follows:

§ 63.646 Storage vessel provisions.

Upon a demonstration of compliance with the standards in § 63.660 by the compliance dates specified in § 63.640(h), the standards in this section shall no longer apply.

* * * * *

(b) * * *

(2) When an owner or operator and the Administrator do not agree on whether the annual average weight percent organic HAP in the stored liquid is above or below 4 percent for a storage vessel at an existing source or above or below 2 percent for a storage vessel at a new source, an appropriate method (based on the type of liquid stored) as published by EPA or a consensus-based standards organization shall be used. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, *http://www.astm.org*), the American National Standards Institute (ANSI, 1819 L Street NW., 6th floor, Washington, DC 20036, (202) 293–8020, *http://www.ansi.org*), the American Gas Association (AGA, 400 North Capitol Street NW., 4th Floor, Washington, DC 20001, (202) 824–7000, *http://www.aga.org*), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, *http://www.asme.org*), the American Petroleum Institute (API, 1220 L Street NW., Washington, DC 20005–4070, (202) 682–8000, *http://www.api.org*), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356–0060, *http://www.naesb.org*).

* * * * *

■ 20. Section 63.647 is amended by:
■ a. Revising paragraph (a);
■ b. Redesignating paragraph (c) as paragraph (d); and
■ c. Adding paragraph (c).

The revisions and additions read as follows:

§ 63.647 Wastewater provisions.

(a) Except as provided in paragraphs (b) and (c) of this section, each owner or operator of a Group 1 wastewater stream shall comply with the requirements of §§ 61.340 through 61.355 of this chapter for each process wastewater stream that meets the definition in § 63.641.

* * * * *

(c) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of § 63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of part 61, subpart FF of this chapter, or the requirements of § 63.670.

* * * * *

■ 21. Section 63.648 is amended by:
■ a. Adding paragraph (a)(3);
■ b. Revising paragraph (c) introductory text; and
■ c. Adding paragraphs (c)(11) and (12) and (j).

The revisions and additions read as follows:

§ 63.648 Equipment leak standards.

(a) * * *

(3) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of § 63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of part 60, subpart VV of this chapter, or the requirements of § 63.670.

* * * * *

(c) In lieu of complying with the existing source provisions of paragraph (a) in this section, an owner or operator may elect to comply with the requirements of §§ 63.161 through 63.169, 63.171, 63.172, 63.175, 63.176, 63.177, 63.179, and 63.180 of subpart H except as provided in paragraphs (c)(1) through (12) and (e) through (i) of this section.

* * * * *

(11) [Reserved]

(12) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of § 63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of §§ 63.172 and 63.180, or the requirements of § 63.670.

* * * * *

(j) Except as specified in paragraph (j)(4) of this section, the owner or operator must comply with the requirements specified in paragraphs (j)(1) and (2) of this section for pressure relief devices, such as relief valves or rupture disks, in organic HAP gas or vapor service instead of the pressure relief device requirements of § 60.482–4 or § 63.165, as applicable. Except as specified in paragraphs (j)(4) and (5) of this section, the owner or operator must also comply with the requirements specified in paragraph (j)(3) of this section for all pressure relief devices.

(1) *Operating requirements.* Except during a pressure release, operate each pressure relief device in organic HAP gas or vapor service with an instrument reading of less than 500 ppm above background as detected by Method 21 of 40 CFR part 60, appendix A–7.

(2) *Pressure release requirements.* For pressure relief devices in organic HAP gas or vapor service, the owner or operator must comply with the applicable requirements in paragraphs (j)(2)(i) through (iii) of this section following a pressure release.

(i) If the pressure relief device does not consist of or include a rupture disk, conduct instrument monitoring, as specified in § 60.485(b) or § 63.180(c), as applicable, no later than 5 calendar days after the pressure relief device returns to organic HAP gas or vapor service following a pressure release to verify that the pressure relief device is operating with an instrument reading of less than 500 ppm.

(ii) If the pressure relief device includes a rupture disk, either comply with the requirements in paragraph (j)(2)(i) of this section (not replacing the rupture disk) or install a replacement disk as soon as practicable after a pressure release, but no later than 5 calendar days after the pressure release. The owner or operator must conduct instrument monitoring, as specified in § 60.485(b) or § 63.180(c), as applicable, no later than 5 calendar days after the pressure relief device returns to organic HAP gas or vapor service following a pressure release to verify that the pressure relief device is operating with an instrument reading of less than 500 ppm.

(iii) If the pressure relief device consists only of a rupture disk, install a replacement disk as soon as practicable after a pressure release, but no later than 5 calendar days after the pressure release. The owner or operator may not initiate startup of the equipment served by the rupture disk until the rupture disc is replaced. The owner or operator must conduct instrument monitoring, as specified in § 60.485(b) or § 63.180(c), as applicable, no later than 5 calendar days after the pressure relief device returns to organic HAP gas or vapor service following a pressure release to verify that the pressure relief device is operating with an instrument reading of less than 500 ppm.

(3) *Pressure release management.* Except as specified in paragraphs (j)(4) and (5) of this section, the owner or operator shall comply with the requirements specified in paragraphs (j)(3)(i) through (v) of this section for all pressure relief devices in organic HAP service no later than January 30, 2019.

(i) The owner or operator must equip each affected pressure relief device with a device(s) or use a monitoring system that is capable of:

(A) Identifying the pressure release;

(B) Recording the time and duration of each pressure release; and

(C) Notifying operators immediately that a pressure release is occurring. The device or monitoring system may be either specific to the pressure relief device itself or may be associated with the process system or piping, sufficient to indicate a pressure release to the atmosphere. Examples of these types of devices and systems include, but are not limited to, a rupture disk indicator, magnetic sensor, motion detector on the pressure relief valve stem, flow monitor, or pressure monitor.

(ii) The owner or operator must apply at least three redundant prevention measures to each affected pressure relief device and document these measures. Examples of prevention measures include:

(A) Flow, temperature, level and pressure indicators with deadman switches, monitors, or automatic actuators.

(B) Documented routine inspection and maintenance programs and/or operator training (maintenance programs and operator training may count as only one redundant prevention measure).

(C) Inherently safer designs or safety instrumentation systems.

(D) Deluge systems.

(E) Staged relief system where initial pressure relief valve (with lower set release pressure) discharges to a flare or other closed vent system and control device.

(iii) If any affected pressure relief device releases to atmosphere as a result of a pressure release event, the owner or operator must perform root cause analysis and corrective action analysis according to the requirement in paragraph (j)(6) of this section and implement corrective actions according to the requirements in paragraph (j)(7) of this section. The owner or operator must also calculate the quantity of organic HAP released during each pressure release event and report this quantity as required in § 63.655(g)(10)(iii). Calculations may be based on data from the pressure relief device monitoring alone or in combination with process parameter monitoring data and process knowledge.

(iv) The owner or operator shall determine the total number of release events occurred during the calendar year for each affected pressure relief device separately. The owner or operator shall also determine the total number of release events for each pressure relief device for which the root cause analysis concluded that the root cause was a *force majeure*event, as defined in this subpart.

(v) Except for pressure relief devices described in paragraphs (j)(4) and (5) of this section, the following release events are a violation of the pressure release management work practice standards.

(A) Any release event for which the root cause of the event was determined to be operator error or poor maintenance.

(B) A second release event not including *force majeure* events from a single pressure relief device in a 3 calendar year period for the same root cause for the same equipment.

(C) A third release event not including *force majeure* events from a single pressure relief device in a 3 calendar year period for any reason.

(4) *Pressure relief devices routed to a control device.* If all releases and potential leaks from a pressure relief device are routed through a closed vent system to a control device, back into the process or to the fuel gas system, the owner or operator is not required to comply with paragraph (j)(1), (2), or (3) (if applicable) of this section. Both the closed vent system and control device (if applicable) must meet the requirements of § 63.644. When complying with this paragraph (j)(4), all references to ‘‘Group 1 miscellaneous process vent’’ in § 63.644 mean ‘‘pressure relief device.’’ If a pressure relief device complying with this paragraph (j)(4) is routed to the fuel gas system, then on and after January 30, 2019, any flares receiving gas from that fuel gas system must be in compliance with § 63.670.

(5) *Pressure relief devices exempted from pressure release management requirements.* The following types of pressure relief devices are not subject to the pressure release management requirements in paragraph (j)(3) of this section.

(i) Pressure relief devices in heavy liquid service, as defined in § 63.641.

(ii) Pressure relief devices that only release material that is liquid at standard conditions (1 atmosphere and 68 degrees Fahrenheit) and that are hard-piped to a controlled drain system (*i.e.*, a drain system meeting the requirements for Group 1 wastewater streams in § 63.647(a)) or piped back to the process or pipeline.

(iii) Thermal expansion relief valves.

(iv) Pressure relief devices designed with a set relief pressure of less than 2.5 psig.

(v) Pressure relief devices that do not have the potential to emit 72 lbs/day or more of VOC based on the valve diameter, the set release pressure, and the equipment contents.

(vi) Pressure relief devices on mobile equipment.

(6) *Root cause analysis and corrective action analysis.* A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a release event. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (j)(6)(i) through (iv) of this section.

(i) You may conduct a single root cause analysis and corrective action analysis for a single emergency event that causes two or more pressure relief devices installed on the same equipment to release.

(ii) You may conduct a single root cause analysis and corrective action analysis for a single emergency event that causes two or more pressure relief devices to release, regardless of the equipment served, if the root cause is reasonably expected to be a force majeure event, as defined in this subpart.

(iii) Except as provided in paragraphs (j)(6)(i) and (ii) of this section, if more than one pressure relief device has a release during the same time period, an initial root cause analysis shall be conducted separately for each pressure relief device that had a release. If the initial root cause analysis indicates that the release events have the same root cause(s), the initially separate root cause analyses may be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(7) *Corrective action implementation.* Each owner or operator required to conduct a root cause analysis and corrective action analysis as specified in paragraphs (j)(3)(iii) and (j)(6) of this section shall implement the corrective action(s) identified in the corrective action analysis in accordance with the applicable requirements in paragraphs (j)(7)(i) through (iii) of this section.

(i) All corrective action(s) must be implemented within 45 days of the event for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that no corrective action should be implemented, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the event.

(ii) For corrective actions that cannot be fully implemented within 45 days following the event for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(iii) No later than 45 days following the event for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

■ 22. Section 63.649 is amended by revising definition of C_c term in the equation in paragraph (c)(6)(i) to read as follows:

§ 63.649 Alternative means of emission limitation: Connectors in gas/vapor service and light liquid service.

* * * * *

(c) * * *

(6) * * *

(i) * * *

C_c = Optional credit for removed connectors = 0.67 × net number (*i.e.,* the total number of connectors removed minus the total added) of connectors in organic HAP service removed from the process unit after the applicability date set forth in § 63.640(h)(3)(iii) for existing process units, and after the date of start-up for new process units. If credits are not taken, then $C_c = 0$.

* * * * *

■ 23. Section 63.650 is amended by revising paragraph (a) and adding paragraph (d) to read as follows:

§ 63.650 Gasoline loading rack provisions.

(a) Except as provided in paragraphs (b) through (d) of this section, each owner or operator of a Group 1 gasoline loading rack classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a petroleum refinery shall comply with subpart R of this part, §§ 63.421, 63.422(a) through (c) and (e), 63.425(a) through (c) and (e) through (i), 63.427(a) and (b), and 63.428(b), (c), (g)(1), (h)(1) through (3), and (k).

* * * * *

(d) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of § 63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of subpart R of this part, or the requirements of § 63.670.

■ 24. Section 63.651 is amended by revising paragraphs (a) and (d) and adding paragraph (e) to read as follows:

§ 63.651 Marine tank vessel loading operation provisions.

(a) Except as provided in paragraphs (b) through (e) of this section, each owner or operator of a marine tank vessel loading operation located at a petroleum refinery shall comply with the requirements of §§ 63.560 through 63.568.

* * * * *

(d) The compliance time of 4 years after promulgation of 40 CFR part 63, subpart Y, does not apply. The compliance time is specified in § 63.640(h)(1).

(e) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of § 63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of subpart Y of this part, or the requirements of § 63.670.

■ 25. Section 63.652 is amended by:

■ a. Revising paragraph (a);

■ b. Removing and reserving paragraph (f)(2); and

■ c. Revising paragraphs (g)(2)(iii)(B)(*1*), (h)(3), (k) introductory text, and (k)(3).

The revisions and additions read as follows:

§ 63.652 Emissions averaging provisions.

(a) This section applies to owners or operators of existing sources who seek to comply with the emission standard in § 63.642(g) by using emissions averaging according to § 63.642(l) rather than following the provisions of §§ 63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651. Existing marine tank vessel loading operations located at the Valdez Marine Terminal source may not comply with the standard by using emissions averaging.

* * * * *

(g) * * *

(2) * * *

(iii) * * *

(B) * * *

(*1*) The percent reduction shall be measured according to the procedures in § 63.116 of subpart G if a combustion control device is used. For a flare meeting the criteria in § 63.116(a) of subpart G or § 63.670, as applicable, or a boiler or process heater meeting the criteria in § 63.645(d) or § 63.116(b) of subpart G, the percentage of reduction shall be 98 percent. If a noncombustion control device is used, percentage of reduction shall be demonstrated by a performance test at the inlet and outlet of the device, or, if testing is not feasible, by a control design evaluation and documented engineering calculations.

* * * * *

(h) * * *

(3) Emissions from storage vessels shall be determined as specified in § 63.150(h)(3) of subpart G, except as follows:

(i) For storage vessels complying with § 63.646:

(A) All references to § 63.119(b) in § 63.150(h)(3) of subpart G shall be replaced with: § 63.119(b) or § 63.119(b) except for § 63.119(b)(5) and (6).

(B) All references to § 63.119(c) in § 63.150(h)(3) of subpart G shall be replaced with: § 63.119(c) or § 63.119(c) except for § 63.119(c)(2).

(C) All references to § 63.119(d) in § 63.150(h)(3) of subpart G shall be replaced with: § 63.119(d) or § 63.119(d) except for § 63.119(d)(2).

(ii) For storage vessels complying with § 63.660:

(A) Section 63.1063(a)(1)(i), (a)(2), and (b) or § 63.1063(a)(1)(i) and (b) shall apply instead of § 63.119(b) in § 63.150(h)(3) of subpart G.

(B) Section 63.1063(a)(1)(ii), (a)(2), and (b) shall apply instead of § 63.119(c) in § 63.150(h)(3) of subpart G.

(C) Section 63.1063(a)(1)(i), (a)(2), and (b) or § 63.1063(a)(1)(i) and (b) shall apply instead of § 63.119(d) in § 63.150(h)(3) of subpart G.

* * * * *

(k) The owner or operator shall demonstrate that the emissions from the emission points proposed to be included in the average will not result in greater hazard or, at the option of the State or local permitting authority, greater risk to human health or the environment than if the emission points were controlled according to the provisions in §§ 63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable.

* * * * *

(3) An emissions averaging plan that does not demonstrate an equivalent or lower hazard or risk to the satisfaction of the State or local permitting authority shall not be approved. The State or local permitting authority may require such adjustments to the emissions averaging plan as are necessary in order to ensure that the average will not result in greater hazard or risk to human health or the environment than would result if the emission points were controlled according to §§ 63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable.

* * * * *

■ 26. Section 63.653 is amended by revising paragraphs (a) introductory text, (a)(3)(i) and (ii), and (a)(7) to read as follows:

§ 63.653 Monitoring, recordkeeping, and implementation plan for emissions averaging.

(a) For each emission point included in an emissions average, the owner or operator shall perform testing, monitoring, recordkeeping, and reporting equivalent to that required for Group 1 emission points complying with §§ 63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable. The specific requirements for miscellaneous process vents, storage vessels, wastewater, gasoline loading racks, and marine tank vessels are identified in paragraphs (a)(1) through (7) of this section.

* * * * *

(3) * * *

(i) Perform the monitoring or inspection procedures in § 63.646 and either § 63.120 of subpart G or § 63.1063 of subpart WW, as applicable; and

(ii) For closed vent systems with control devices, conduct an initial design evaluation as specified in § 63.646 and either § 63.120(d) of subpart G or § 63.985(b) of subpart SS, as applicable.

* * * * *

(7) If an emission point in an emissions average is controlled using a pollution prevention measure or a device or technique for which no monitoring parameters or inspection procedures are specified in §§ 63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable, the owner or operator shall establish a site-specific monitoring parameter and shall submit the information specified in § 63.655(h)(4) in the Implementation Plan.

* * * * *

■ 27. Section 63.655 is amended by:

■ a. Revising paragraphs (f) introductory text, (f)(1) introductory text, (f)(1)(i)(A) introductory text, (f)(1)(i)(A)(*2*) and (*3*), (f)(1)(i)(B) introductory text, (f)(1)(i)(B)(*2*), (f)(1)(i)(D)(*2*), (f)(1)(iv) introductory text, and (f)(1)(iv)(A);

■ b. Adding paragraphs (f)(1)(vii) and (viii);

■ c. Revising paragraphs (f)(2) introductory text, (f)(3) introductory text, the first sentence of (f)(6), (g) introductory text, (g)(1) through (5), (g)(6)(i)(D), (g)(6)(iii), and (g)(7)(i);

■ d. Adding paragraphs (g)(10) through (14);
■ e. Removing and reserving paragraph (h)(1);
■ f. Revising paragraphs (h)(2) introductory text, (h)(2)(i)(B), (h)(2)(ii), and (h)(5)(iii);
■ g. Adding paragraphs (h)(8) and (9) and (i) introductory text;
■ h. Revising paragraph (i)(1) introductory text and paragraph (i)(1)(ii);
■ i. Adding paragraphs (i)(1)(v) and (vi);
■ j. Redesignating paragraphs (i)(4) and (5) as paragraphs (i)(5) and (6), respectively;
■ k. Adding paragraph (i)(4);
■ l. Revising newly redesignated paragraph (i)(5) introductory text; and
■ m. Adding paragraphs (i)(7) through (12).

The revisions and additions read as follows:

§ 63.655 Reporting and recordkeeping requirements.

* * * * *

(f) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status report within 150 days after the compliance dates specified in § 63.640(h) with the exception of Notification of Compliance Status reports submitted to comply with § 63.640(l)(3) and for storage vessels subject to the compliance schedule specified in § 63.640(h)(2). Notification of Compliance Status reports required by § 63.640(l)(3) and for storage vessels subject to the compliance dates specified in § 63.640(h)(2) shall be submitted according to paragraph (f)(6) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If the required information has been submitted before the date 150 days after the compliance date specified in § 63.640(h), a separate Notification of Compliance Status report is not required within 150 days after the compliance dates specified in § 63.640(h). If an owner or operator submits the information specified in paragraphs (f)(1) through (5) of this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information. Each owner or operator of a gasoline loading rack classified under Standard Industrial Classification Code 2911 located within a contiguous area and under common control with a petroleum refinery subject to the standards of this subpart shall submit the Notification of Compliance Status report required by subpart R of this part within 150 days after the compliance dates specified in § 63.640(h).

(1) The Notification of Compliance Status report shall include the information specified in paragraphs (f)(1)(i) through (viii) of this section.

(i) * * *

(A) Identification of each storage vessel subject to this subpart, and for each Group 1 storage vessel subject to this subpart, the information specified in paragraphs (f)(1)(i)(A)(*1*) through (*3*) of this section. This information is to be revised each time a Notification of Compliance Status report is submitted for a storage vessel subject to the compliance schedule specified in § 63.640(h)(2) or to comply with § 63.640(l)(3).

* * * * *

(*2*) For storage vessels subject to the compliance schedule specified in § 63.640(h)(2) that are not complying with § 63.646, the anticipated compliance date.

(*3*) For storage vessels subject to the compliance schedule specified in § 63.640(h)(2) that are complying with § 63.646 and the Group 1 storage vessels described in § 63.640(l), the actual compliance date.

(B) If a closed vent system and a control device other than a flare is used to comply with § 63.646 or § 63.660, the owner or operator shall submit:

* * * * *

(*2*) The design evaluation documentation specified in § 63.120(d)(1)(i) of subpart G or § 63.985(b)(1)(i) of subpart SS (as applicable), if the owner or operator elects to prepare a design evaluation; or

* * * * *

(D) * * *

(*2*) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by § 63.120(e) of subpart G or § 63.987(b) of subpart SS or § 63.670(h), as applicable; and

* * * * *

(iv) For miscellaneous process vents controlled by flares, initial compliance test results including the information in paragraphs (f)(1)(iv)(A) and (B) of this section.

(A) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by §§ 63.645 and 63.116(a) of subpart G or § 63.670(h), as applicable; and

* * * * *

(vii) For pressure relief devices in organic HAP service subject to the requirements in § 63.648(j)(3)(i) and (ii), this report shall include the information specified in paragraphs (f)(1)(vii)(A) and (B) of this section.

(A) A description of the monitoring system to be implemented, including the relief devices and process parameters to be monitored, and a description of the alarms or other methods by which operators will be notified of a pressure release.

(B) A description of the prevention measures to be implemented for each affected pressure relief device.

(viii) For each delayed coking unit, identification of whether the unit is an existing affected source or a new affected source and whether monitoring will be conducted as specified in § 63.657(b) or (c).

(2) If initial performance tests are required by §§ 63.643 through 63.653, the Notification of Compliance Status report shall include one complete test report for each test method used for a particular source. On and after February 1, 2016, performance tests shall be submitted according to paragraph (h)(9) of this section.

* * * * *

(3) For each monitored parameter for which a range is required to be established under § 63.120(d) of subpart G or § 63.985(b) of subpart SS for storage vessels or § 63.644 for miscellaneous process vents, the Notification of Compliance Status report shall include the information in paragraphs (f)(3)(i) through (iii) of this section.

* * * * *

(6) Notification of Compliance Status reports required by § 63.640(l)(3) and for storage vessels subject to the compliance dates specified in § 63.640(h)(2) shall be submitted no later than 60 days after the end of the 6-month period during which the change or addition was made that resulted in the Group 1 emission point or the existing Group 1 storage vessel was brought into compliance, and may be combined with the periodic report. * * *

(g) The owner or operator of a source subject to this subpart shall submit Periodic Reports no later than 60 days after the end of each 6-month period when any of the information specified in paragraphs (g)(1) through (7) of this section or paragraphs (g)(9) through (14) of this section is collected. The first 6-month period shall begin on the date the Notification of Compliance Status report is required to be submitted. A Periodic Report is not required if none of the events identified in paragraphs (g)(1) through (7) of this section or paragraphs (g)(9) through (14) of this section occurred during the 6-month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emission averages, as provided in paragraph (g)(8) of this section. An owner or operator may submit reports required by other regulations in place of or as part of the Periodic Report required by this paragraph (g) if the reports contain the information required by paragraphs (g)(1) through (14) of this section.

(1) For storage vessels, Periodic Reports shall include the information specified for Periodic Reports in paragraphs (g)(2) through (5) of this section. Information related to gaskets, slotted membranes, and sleeve seals is not required for storage vessels that are part of an existing source complying with § 63.646.

(2) *Internal floating roofs.* (i) An owner or operator who elects to comply with § 63.646 by using a fixed roof and an internal floating roof or by using an external floating roof converted to an internal floating roof shall submit the results of each inspection conducted in accordance with § 63.120(a) of subpart G in which a failure is detected in the control equipment.

(A) For vessels for which annual inspections are required under § 63.120(a)(2)(i) or (a)(3)(ii) of subpart G, the specifications and requirements listed in paragraphs (g)(2)(i)(A)(*1*) through (*3*) of this section apply.

(*1*) A failure is defined as any time in which the internal floating roof is not resting on the surface of the liquid inside the storage vessel and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears, or other openings in the seal or seal fabric; or there are visible gaps between the seal and the wall of the storage vessel.

(*2*) Except as provided in paragraph (g)(2)(i)(A)(*3*) of this section, each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made or the date the storage vessel was emptied.

(*3*) If an extension is utilized in accordance with § 63.120(a)(4) of subpart G, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in § 63.120(a)(4) of subpart G; and describe the date the storage vessel was emptied and the nature of and date the repair was made.

(B) For vessels for which inspections are required under § 63.120(a)(2)(ii), (a)(3)(i), or (a)(3)(iii) of subpart G (*i.e.*, internal inspections), the specifications and requirements listed in paragraphs (g)(2)(i)(B)(*1*) and (*2*) of this section apply.

(*1*) A failure is defined as any time in which the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal (if one has been installed) has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than a 10 percent open.

(*2*) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(ii) An owner or operator who elects to comply with § 63.660 by using a fixed roof and an internal floating roof shall submit the results of each inspection conducted in accordance with § 63.1063(c)(1), (d)(1), and (d)(2) of subpart WW in which a failure is detected in the control equipment. For vessels for which inspections are required under § 63.1063(c) and (d), the specifications and requirements listed in paragraphs (g)(2)(ii)(A) through (C) of this section apply.

(A) A failure is defined in § 63.1063(d)(1) of subpart WW.

(B) Each Periodic Report shall include a copy of the inspection record required by § 63.1065(b) of subpart WW when a failure occurs.

(C) An owner or operator who elects to use an extension in accordance with § 63.1063(e)(2) of subpart WW shall, in the next Periodic Report, submit the documentation required by § 63.1063(e)(2).

(3) *External floating roofs.* (i) An owner or operator who elects to comply with § 63.646 by using an external floating roof shall meet the periodic reporting requirements specified in paragraphs (g)(3)(i)(A) through (C) of this section.

(A) The owner or operator shall submit, as part of the Periodic Report, documentation of the results of each seal gap measurement made in accordance with § 63.120(b) of subpart G in which the seal and seal gap requirements of § 63.120(b)(3), (4), (5), or (6) of subpart G are not met. This documentation shall include the information specified in paragraphs (g)(3)(i)(A)(*1*) through (*4*) of this section.

(*1*) The date of the seal gap measurement.

(*2*) The raw data obtained in the seal gap measurement and the calculations described in § 63.120(b)(3) and (4) of subpart G.

(*3*) A description of any seal condition specified in § 63.120(b)(5) or (6) of subpart G that is not met.

(*4*) A description of the nature of and date the repair was made, or the date the storage vessel was emptied.

(B) If an extension is utilized in accordance with § 63.120(b)(7)(ii) or (b)(8) of subpart G, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in § 63.120(b)(7)(ii) or (b)(8) of subpart G, as applicable; and describe the date the vessel was emptied and the nature of and date the repair was made.

(C) The owner or operator shall submit, as part of the Periodic Report, documentation of any failures that are identified during visual inspections required by § 63.120(b)(10) of subpart G. This documentation shall meet the specifications and requirements in paragraphs (g)(3)(i)(C)(*1*) and (*2*) of this section.

(*1*) A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than 10 percent open area.

(*2*) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(ii) An owner or operator who elects to comply with § 63.660 by using an external floating roof shall meet the periodic reporting requirements specified in paragraphs (g)(3)(ii)(A) and (B) of this section.

(A) For vessels for which inspections are required under § 63.1063(c)(2), (d)(1), and (d)(3) of subpart WW, the owner or operator shall submit, as part of the Periodic Report, a copy of the inspection record required by § 63.1065(b) of subpart WW when a failure occurs. A failure is defined in § 63.1063(d)(1).

(B) An owner or operator who elects to use an extension in accordance with § 63.1063(e)(2) or (c)(2)(iv)(B) of subpart WW shall, in the next Periodic Report, submit the documentation required by those paragraphs.

(4) [Reserved]

(5) An owner or operator who elects to comply with § 63.646 or § 63.660 by installing a closed vent system and control device shall submit, as part of the next Periodic Report, the information specified in paragraphs (g)(5)(i) through (v) of this section, as applicable.

(i) The Periodic Report shall include the information specified in paragraphs (g)(5)(i)(A) and (B) of this section for those planned routine maintenance operations that would require the control device not to meet the requirements of either § 63.119(e)(1) or (2) of subpart G, § 63.985(a) and (b) of subpart SS, or § 63.670, as applicable.

(A) A description of the planned routine maintenance that is anticipated to be performed for the control device during the next 6 months. This description shall include the type of maintenance necessary, planned frequency of maintenance, and lengths of maintenance periods.

(B) A description of the planned routine maintenance that was performed for the control device during the previous 6 months. This description shall include the type of maintenance performed and the total number of hours during those 6 months that the control device did not meet the requirements of either § 63.119(e)(1) or (2) of subpart G, § 63.985(a) and (b) of subpart SS, or § 63.670, as applicable, due to planned routine maintenance.

(ii) If a control device other than a flare is used, the Periodic Report shall describe each occurrence when the monitored parameters were outside of the parameter ranges documented in the Notification of Compliance Status report. The description shall include: Identification of the control device for which the measured parameters were outside of the established ranges, and causes for the measured parameters to be outside of the established ranges.

(iii) If a flare is used prior to January 30, 2019 and prior to electing to comply with the requirements in § 63.670, the Periodic Report shall describe each occurrence when the flare does not meet the general control device requirements specified in § 63.11(b) of subpart A and shall include: Identification of the flare that does not meet the general requirements specified in § 63.11(b) of subpart A, and reasons the flare did not meet the general requirements specified in § 63.11(b) of subpart A.

(iv) If a flare is used on or after the date for which compliance with the requirements in § 63.670 is elected, which can be no later than January 30, 2019, the Periodic Report shall include the items specified in paragraph (g)(11) of this section.

(v) An owner or operator who elects to comply with § 63.660 by installing an alternate control device as described in § 63.1064 of subpart WW shall submit, as part of the next Periodic Report, a written application as described in § 63.1066(b)(3) of subpart WW.

(6) * * *

(i) * * *

(D) For data compression systems under paragraph (h)(5)(iii) of this section, an operating day when the monitor operated for less than 75 percent of the operating hours or a day when less than 18 monitoring values were recorded.

* * * * *

(iii) For periods in closed vent systems when a Group 1 miscellaneous process vent stream was detected in the bypass line or diverted from the control device and either directly to the atmosphere or to a control device that does not comply with the requirements in § 63.643(a), report the date, time, duration, estimate of the volume of gas, the concentration of organic HAP in the gas and the resulting mass emissions of organic HAP that bypassed the control device. For periods when the flow indicator is not operating, report the date, time, and duration.

(7) * * *

(i) Results of the performance test shall include the identification of the source tested, the date of the test, the percentage of emissions reduction or outlet pollutant concentration reduction (whichever is needed to determine compliance) for each run and for the average of all runs, and the values of the monitored operating parameters.

* * * * *

(10) For pressure relief devices subject to the requirements § 63.648(j), Periodic Reports must include the information specified in paragraphs (g)(10)(i) through (iii) of this section.

(i) For pressure relief devices in organic HAP gas or vapor service, pursuant to § 63.648(j)(1), report any instrument reading of 500 ppm or greater.

(ii) For pressure relief devices in organic HAP gas or vapor service subject to § 63.648(j)(2), report confirmation that any monitoring required to be done during the reporting period to show compliance was conducted.

(iii) For pressure relief devices in organic HAP service subject to § 63.648(j)(3), report each pressure release to the atmosphere, including duration of the pressure release and estimate of the mass quantity of each organic HAP released, and the results of any root cause analysis and corrective action analysis completed during the reporting period, including the corrective actions implemented during the reporting period and, if applicable, the implementation schedule for planned corrective actions to be implemented subsequent to the reporting period.

(11) For flares subject to § 63.670, Periodic Reports must include the information specified in paragraphs (g)(11)(i) through (iv) of this section.

(i) Records as specified in paragraph (i)(9)(i) of this section for each 15-minute block during which there was at least one minute when regulated material is routed to a flare and no pilot flame is present.

(ii) Visible emission records as specified in paragraph (i)(9)(ii)(C) of this section for each period of 2 consecutive hours during which visible emissions exceeded a total of 5 minutes.

(iii) The 15-minute block periods for which the applicable operating limits specified in § 63.670(d) through (f) are not met. Indicate the date and time for the period, the net heating value operating parameter(s) determined following the methods in § 63.670(k) through (n) as applicable.

(iv) For flaring events meeting the criteria in § 63.670(o)(3):

(A) The start and stop time and date of the flaring event.

(B) The length of time for which emissions were visible from the flare during the event.

(C) The periods of time that the flare tip velocity exceeds the maximum flare tip velocity determined using the methods in § 63.670(d)(2) and the maximum 15-minute block average flare tip velocity recorded during the event.

(D) Results of the root cause and corrective actions analysis completed during the reporting period, including the corrective actions implemented during the reporting period and, if applicable, the implementation schedule for planned corrective actions to be implemented subsequent to the reporting period.

(12) For delayed coking units, the Periodic Report must include the information specified in paragraphs (g)(12)(i) through (iv) of this section.

(i) For existing source delayed coking units, any 60-cycle average exceeding the applicable limit in § 63.657(a)(1).

(ii) For new source delayed coking units, any direct venting event exceeding the applicable limit in § 63.657(a)(2).

(iii) The total number of double quenching events performed during the reporting period.

(iv) For each double quenching draining event when the drain water temperature exceeded 210 °F, report the drum, date, time, the coke drum vessel pressure or temperature, as applicable, when pre-vent draining was initiated, and the maximum drain water temperature during the pre-vent draining period.

(13) For maintenance vents subject to the requirements in § 63.643(c), Periodic Reports must include the information specified in paragraphs (g)(13)(i) through (iv) of this section for any release exceeding the applicable limits in § 63.643(c)(1). For the purposes of this reporting requirement, owners or operators complying with § 63.643(c)(1)(iv) must report each venting event for which the lower explosive limit is 20 percent or greater.

(i) Identification of the maintenance vent and the equipment served by the maintenance vent.

(ii) The date and time the maintenance vent was opened to the atmosphere.

(iii) The lower explosive limit, vessel pressure, or mass of VOC in the equipment, as applicable, at the start of atmospheric venting. If the 5 psig vessel pressure option in § 63.643(c)(1)(ii) was used and active purging was initiated while the lower explosive limit was 10 percent or greater, also include the lower explosive limit of the vapors at the time active purging was initiated.

(iv) An estimate of the mass of organic HAP released during the entire atmospheric venting event.

(14) Any changes in the information provided in a previous Notification of Compliance Status report.

(h) * * *

(2) For storage vessels, notifications of inspections as specified in paragraphs (h)(2)(i) and (ii) of this section.

(i) * * *

(B) Except as provided in paragraph (h)(2)(i)(C) of this section, if the internal inspection required by § 63.120(a)(2), (a)(3), or (b)(10) of subpart G or § 63.1063(d)(1) of subpart WW is not planned and the owner or operator could not have known about the inspection 30 calendar days in advance of refilling the vessel with organic HAP, the owner or operator shall notify the Administrator at least 7 calendar days prior to refilling of the storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. This notification, including the written documentation, may also be made in writing and sent so that it is received by the Administrator at least 7 calendar days prior to the refilling.

* * * * *

(ii) In order to afford the Administrator the opportunity to have an observer present, the owner or operator of a storage vessel equipped with an external floating roof shall notify the Administrator of any seal gap measurements. The notification shall be made in writing at least 30 calendar days in advance of any gap measurements required by § 63.120(b)(1) or (2) of subpart G or § 63.1062(d)(3) of subpart WW. The State or local permitting authority can waive this notification requirement for all or some storage vessels subject to the rule or can allow less than 30 calendar days' notice.

* * * * *

(5) * * *

(iii) An owner or operator may use an automated data compression recording system that does not record monitored operating parameter values at a set frequency (for example, once every hour) but records all values that meet set criteria for variation from previously recorded values.

(A) The system shall be designed to:

(*1*) Measure the operating parameter value at least once every hour.

(*2*) Record at least 24 values each day during periods of operation.

(*3*) Record the date and time when monitors are turned off or on.

(*4*) Recognize unchanging data that may indicate the monitor is not functioning properly, alert the operator, and record the incident.

(*5*) Compute daily average values of the monitored operating parameter based on recorded data.

(B) You must maintain a record of the description of the monitoring system and data compression recording system including the criteria used to determine which monitored values are recorded and retained, the method for calculating daily averages, and a demonstrations that they system meets all criteria of paragraph (h)(5)(iii)(A) of this section.

* * * * *

(8) For fenceline monitoring systems subject to § 63.658, within 45 calendar days after the end of each quarterly reporting period covered by the periodic report, each owner or operator shall submit the following information to the EPA's Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The owner or operator need not transmit this data prior to obtaining 12 months of data.

(i) Individual sample results for each monitor for each sampling period during the quarterly reporting period. For the first reporting period and for any period in which a passive monitor is added or moved, the owner or operator shall report the coordinates of all of the passive monitor locations. The owner or operator shall determine the coordinates using an instrument with an accuracy of at least 3 meters. Coordinates shall be in decimal degrees with at least five decimal places.

(ii) The biweekly annual average concentration difference (Δc) values for benzene for the quarterly reporting period.

(iii) Notation for each biweekly value that indicates whether background correction was used, all measurements in the sampling period were below detection, or whether an outlier was removed from the sampling period data set.

(9) On and after February 1, 2016, if required to submit the results of a performance test or CEMS performance evaluation, the owner or operator shall submit the results according to the procedures in paragraphs (h)(9)(i) and (ii) of this section.

(i) Within 60 days after the date of completing each performance test as required by this subpart, the owner or operator shall submit the results of the performance tests following the procedure specified in either paragraph (h)(9)(i)(A) or (B) of this section.

(A) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*) at the time of the test, the owner or operator must submit the results of the performance test to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If an owner or operator claims that some of the performance test information being submitted is confidential business information (CBI), the owner or operator must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic storage media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/

CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (h)(9)(i)(A).

(B) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, the owner or operator must submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

(ii) Within 60 days after the date of completing each CEMS performance evaluation as required by this subpart, the owner or operator must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(9)(ii)(A) or (B) of this section.

(A) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, the owner or operator must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If an owner or operator claims that some of the performance evaluation information being submitted is CBI, the owner or operator must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic storage media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (h)(9)(ii)(A).

(B) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, the owner or operator must submit the results of the performance evaluation to the Administrator at the appropriate address listed in § 63.13.

(i) *Recordkeeping.* Each owner or operator of a source subject to this subpart shall keep copies of all applicable reports and records required by this subpart for at least 5 years except as otherwise specified in paragraphs (i)(1) through (12) of this section. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, flash drive, floppy disk, magnetic tape, or microfiche.

(1) Each owner or operator subject to the storage vessel provisions in § 63.646 shall keep the records specified in § 63.123 of subpart G except as specified in paragraphs (i)(1)(i) through (iv) of this section. Each owner or operator subject to the storage vessel provisions in § 63.660 shall keep records as specified in paragraphs (i)(1)(v) and (vi) of this section.

* * * * *

(ii) All references to § 63.122 in § 63.123 of subpart G shall be replaced with § 63.655(e).

* * * * *

(v) Each owner or operator of a Group 1 storage vessel subject to the provisions in § 63.660 shall keep records as specified in § 63.1065 or § 63.998, as applicable.

(vi) Each owner or operator of a Group 2 storage vessel shall keep the records specified in § 63.1065(a) of subpart WW. If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources or 2 percent for new sources, a record of any data, assumptions, and procedures used to make this determination shall be retained.

* * * * *

(4) For each closed vent system that contains bypass lines that could divert a vent stream away from the control device and either directly to the atmosphere or to a control device that does not comply with the requirements in § 63.643(a), the owner or operator shall keep a record of the information specified in either paragraph (i)(4)(i) or (ii) of this section, as applicable.

(i) The owner or operator shall maintain records of periods when flow was detected in the bypass line, including the date and time and the duration of the flow in the bypass line. For each flow event, the owner or operator shall maintain records sufficient to determine whether or not the detected flow included flow of a Group 1 miscellaneous process vent stream requiring control. For periods when the Group 1 miscellaneous process vent stream requiring control is diverted from the control device and released either directly to the atmosphere or to a control device that does not comply with the requirements in § 63.643(a), the owner or operator shall include an estimate of the volume of gas, the concentration of organic HAP in the gas and the resulting emissions of organic HAP that bypassed the control device using process knowledge and engineering estimates.

(ii) Where a seal mechanism is used to comply with § 63.644(c)(2), hourly records of flow are not required. In such cases, the owner or operator shall record the date that the monthly visual inspection of the seals or closure mechanisms is completed. The owner or operator shall also record the occurrence of all periods when the seal or closure mechanism is broken, the bypass line valve position has changed or the key for a lock-and-key type lock has been checked out. The owner or operator shall include an estimate of the volume of gas, the concentration of organic HAP in the gas and the resulting mass emissions of organic HAP from the Group 1 miscellaneous process vent stream requiring control that bypassed the control device or records sufficient to demonstrate that there was no flow of a Group 1 miscellaneous process vent stream requiring control during the period.

(5) The owner or operator of a heat exchange system subject to this subpart shall comply with the recordkeeping requirements in paragraphs (i)(5)(i) through (v) of this section and retain these records for 5 years.

* * * * *

(7) Each owner or operator subject to the delayed coking unit decoking operations provisions in § 63.657 must maintain records specified in paragraphs (i)(7)(i) through (iii) of this section.

(i) The average pressure or temperature, as applicable, for the 5-minute period prior to venting to the atmosphere, draining, or deheading the coke drum for each cooling cycle for each coke drum.

(ii) If complying with the 60-cycle rolling average, each 60-cycle rolling average pressure or temperature, as applicable, considering all coke drum venting events in the existing affected source.

(iii) For double-quench cooling cycles:

(A) The date, time and duration of each pre-vent draining event.

(B) The pressure or temperature of the coke drum vessel, as applicable, for the 15 minute period prior to the pre-vent draining.

(C) The drain water temperature at 1-minute intervals from the start of pre-vent draining to the complete closure of the drain valve.

(8) For fenceline monitoring systems subject to § 63.658, each owner or operator shall keep the records specified in paragraphs (i)(8)(i) through (x) of this section on an ongoing basis.

(i) Coordinates of all passive monitors, including replicate samplers and field blanks, and if applicable, the meteorological station. The owner or operator shall determine the coordinates using an instrument with an accuracy of at least 3 meters. The coordinates shall be in decimal degrees with at least five decimal places.

(ii) The start and stop times and dates for each sample, as well as the tube identifying information.

(iii) Sampling period average temperature and barometric pressure measurements.

(iv) For each outlier determined in accordance with Section 9.2 of Method 325A of appendix A of this part, the sampler location of and the concentration of the outlier and the evidence used to conclude that the result is an outlier.

(v) For samples that will be adjusted for a background, the location of and the concentration measured simultaneously by the background sampler, and the perimeter samplers to which it applies.

(vi) Individual sample results, the calculated Δc for benzene for each sampling period and the two samples used to determine it, whether background correction was used, and the annual average Δc calculated after each sampling period.

(vii) Method detection limit for each sample, including co-located samples and blanks.

(viii) Documentation of corrective action taken each time the action level was exceeded.

(ix) Other records as required by Methods 325A and 325B of appendix A of this part.

(x) If a near-field source correction is used as provided in § 63.658(i), records of hourly meteorological data, including temperature, barometric pressure, wind speed and wind direction, calculated daily unit vector wind direction and daily sigma theta, and other records specified in the site-specific monitoring plan.

(9) For each flare subject to § 63.670, each owner or operator shall keep the records specified in paragraphs (i)(9)(i) through (xii) of this section up-to-date and readily accessible, as applicable.

(i) Retain records of the output of the monitoring device used to detect the presence of a pilot flame as required in § 63.670(b) for a minimum of 2 years. Retain records of each 15-minute block during which there was at least one minute that no pilot flame is present when regulated material is routed to a flare for a minimum of 5 years.

(ii) Retain records of daily visible emissions observations or video surveillance images required in § 63.670(h) as specified in the paragraphs (i)(9)(ii)(A) through (C), as applicable, for a minimum of 3 years.

(A) If visible emissions observations are performed using Method 22 at 40 CFR part 60, appendix A–7, the record must identify whether the visible emissions observation was performed, the results of each observation, total duration of observed visible emissions, and whether it was a 5-minute or 2-hour observation. If the owner or operator performs visible emissions observations more than one time during a day, the record must also identify the date and time of day each visible emissions observation was performed.

(B) If video surveillance camera is used, the record must include all video surveillance images recorded, with time and date stamps.

(C) For each 2 hour period for which visible emissions are observed for more than 5 minutes in 2 consecutive hours, the record must include the date and time of the 2 hour period and an estimate of the cumulative number of minutes in the 2 hour period for which emissions were visible.

(iii) The 15-minute block average cumulative flows for flare vent gas and, if applicable, total steam, perimeter assist air, and premix assist air specified to be monitored under § 63.670(i), along with the date and time interval for the 15-minute block. If multiple monitoring locations are used to determine cumulative vent gas flow, total steam, perimeter assist air, and premix assist air, retain records of the 15-minute block average flows for each monitoring location for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years. If pressure and temperature monitoring is used, retain records of the 15-minute block average temperature, pressure and molecular weight of the flare vent gas or assist gas stream for each measurement location used to determine the 15-minute block average cumulative flows for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years.

(iv) The flare vent gas compositions specified to be monitored under § 63.670(j). Retain records of individual component concentrations from each compositional analyses for a minimum of 2 years. If NHVvg analyzer is used, retain records of the 15-minute block average values for a minimum of 5 years.

(v) Each 15-minute block average operating parameter calculated following the methods specified in § 63.670(k) through (n), as applicable.

(vi) [Reserved]

(vii) All periods during which operating values are outside of the applicable operating limits specified in § 63.670(d) through (f) when regulated material is being routed to the flare.

(viii) All periods during which the owner or operator does not perform flare monitoring according to the procedures in § 63.670(g) through (j).

(ix) Records of periods when there is flow of vent gas to the flare, but when there is no flow of regulated material to the flare, including the start and stop time and dates of periods of no regulated material flow.

(x) Records when the flow of vent gas exceeds the smokeless capacity of the flare, including start and stop time and dates of the flaring event.

(xi) Records of the root cause analysis and corrective action analysis conducted as required in § 63.670(o)(3), including an identification of the affected facility, the date and duration of the event, a statement noting whether the event resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under § 63.670(o)(5)(i).

(xii) For any corrective action analysis for which implementation of corrective actions are required in § 63.670(o)(5), a description of the corrective action(s) completed within the first 45 days following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(10) [Reserved]

(11) For each pressure relief device subject to the pressure release management work practice standards in § 63.648(j)(3), the owner or operator shall keep the records specified in paragraphs (i)(11)(i) through (iii) of this section.

(i) Records of the prevention measures implemented as required in § 63.648(j)(3)(ii), if applicable.

(ii) Records of the number of releases during each calendar year and the number of those releases for which the root cause was determined to be a force majeure event. Keep these records for the current calendar year and the past five calendar years.

(iii) For each release to the atmosphere, the owner or operator shall keep the records specified in paragraphs (i)(11)(iii)(A) through (D) of this section.

(A) The start and end time and date of each pressure release to the atmosphere.

(B) Records of any data, assumptions, and calculations used to estimate of the mass quantity of each organic HAP released during the event.

(C) Records of the root cause analysis and corrective action analysis conducted as required in § 63.648(j)(3)(iii), including an identification of the affected facility, the date and duration of the event, a statement noting whether the event resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under § 63.648(j)(7)(i).

(D) For any corrective action analysis for which implementation of corrective actions are required in § 63.648(j)(7), a description of the corrective action(s) completed within the first 45 days following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(12) For each maintenance vent opening subject to the requirements in § 63.643(c), the owner or operator shall keep the applicable records specified in (i)(12)(i) through (v) of this section.

(i) The owner or operator shall maintain standard site procedures used to deinventory equipment for safety purposes (*e.g.,* hot work or vessel entry procedures) to document the procedures used to meet the requirements in § 63.643(c). The current copy of the procedures shall be retained and available on-site at all times. Previous versions of the standard site procedures, is applicable, shall be retained for five years.

(ii) If complying with the requirements of § 63.643(c)(1)(i) and the lower explosive limit at the time of the vessel opening exceeds 10 percent, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and the lower explosive limit at the time of the vessel opening.

(iii) If complying with the requirements of § 63.643(c)(1)(ii) and either the vessel pressure at the time of the vessel opening exceeds 5 psig or the lower explosive limit at the time of the active purging was initiated exceeds 10 percent, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, the pressure of the vessel or equipment at the time of discharge to the atmosphere and, if applicable, the lower explosive limit of the vapors in the equipment when active purging was initiated.

(iv) If complying with the requirements of § 63.643(c)(1)(iii), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and records used to estimate the total quantity of VOC in the equipment at the time the maintenance vent was opened to the atmosphere for each applicable maintenance vent opening.

(v) If complying with the requirements of § 63.643(c)(1)(iv), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, records documenting the lack of a pure hydrogen supply, the date of maintenance vent opening, and the lower explosive limit of the vapors in the equipment at the time of discharge to the atmosphere for each applicable maintenance vent opening.

■ 28. Section 63.656 is amended by revising paragraph (c)(1) to read as follows:

§ 63.656 Implementation and enforcement.

* * * * *

(c) * * *

(1) Approval of alternatives to the requirements in §§ 63.640, 63.642(g) through (l), 63.643, 63.646 through 63.652, 63.654, 63.657 through 63.660, and 63.670. Where these standards reference another subpart, the cited provisions will be delegated according to the delegation provisions of the referenced subpart. Where these standards reference another subpart and modify the requirements, the requirements shall be modified as described in this subpart. Delegation of the modified requirements will also occur according to the delegation provisions of the referenced subpart.

* * * * *

■ 29. Section 63.657 is added to read as follows:

§ 63.657 Delayed coking unit decoking operation standards.

(a) Except as provided in paragraphs (e) and (f) of this section, each owner or operator of a delayed coking unit shall depressure each coke drum to a closed blowdown system until the coke drum vessel pressure or temperature measured at the top of the coke drum or in the overhead line of the coke drum as near as practical to the coke drum meets the applicable limits specified in paragraph (a)(1) or (2) of this section prior to venting to the atmosphere, draining or deheading the coke drum at the end of the cooling cycle.

(1) For delayed coking units at an existing affected source, meet either:

(i) An average vessel pressure of 2 psig determined on a rolling 60-event average; or

(ii) An average vessel temperature of 220 degrees Fahrenheit determined on a rolling 60-event average.

(2) For delayed coking units at a new affected source, meet either:

(i) A vessel pressure of 2.0 psig for each decoking event; or

(ii) A vessel temperature of 218 degrees Fahrenheit for each decoking event.

(b) Each owner or operator of a delayed coking unit complying with the pressure limits in paragraph (a)(1)(i) or (a)(2)(i) of this section shall install, operate, calibrate, and maintain a monitoring system, as specified in paragraphs (b)(1) through (5) of this section, to determine the coke drum vessel pressure.

(1) The pressure monitoring system must be in a representative location (at the top of the coke drum or in the overhead line as near as practical to the coke drum) that minimizes or eliminates pulsating pressure, vibration, and, to the extent practical, internal and external corrosion.

(2) The pressure monitoring system must be capable of measuring a pressure of 2.0 psig within ±0.5 psig.

(3) The pressure monitoring system must be verified annually or at the frequency recommended by the instrument manufacturer. The pressure monitoring system must be verified following any period of more than 24 hours throughout which the pressure exceeded the maximum rated pressure of the sensor, or the data recorder was off scale.

(4) All components of the pressure monitoring system must be visually inspected for integrity, oxidation and galvanic corrosion every 3 months, unless the system has a redundant pressure sensor.

(5) The output of the pressure monitoring system must be reviewed

daily to ensure that the pressure readings fluctuate as expected between operating and cooling/decoking cycles to verify the pressure taps are not plugged. Plugged pressure taps must be unplugged or otherwise repaired prior to the next operating cycle.

(c) Each owner or operator of a delayed coking unit complying with the temperature limits in paragraph (a)(1)(ii) or (a)(2)(ii) of this section shall install, operate, calibrate, and maintain a continuous parameter monitoring system to measure the coke drum vessel temperature (at the top of the coke drum or in the overhead line as near as practical to the coke drum) according to the requirements specified in table 13 of this subpart.

(d) The owner or operator of a delayed coking unit shall determine the coke drum vessel pressure or temperature, as applicable, on a 5-minute rolling average basis while the coke drum is vented to the closed blowdown system and shall use the last complete 5-minute rolling average pressure or temperature just prior to initiating steps to isolate the coke drum prior to venting, draining or deheading to demonstrate compliance with the requirements in paragraph (a) of this section. Pressure or temperature readings after initiating steps to isolate the coke drum from the closed blowdown system just prior to atmospheric venting, draining, or deheading the coke drum shall not be used in determining the average coke drum vessel pressure or temperature for the purpose of compliance with the requirements in paragraph (a) of this section.

(e) The owner or operator of a delayed coking unit using the ‘‘water overflow’’ method of coke cooling must hardpipe the overflow water or otherwise prevent exposure of the overflow water to the atmosphere when transferring the overflow water to the overflow water storage tank whenever the coke drum vessel temperature exceeds 220 degrees Fahrenheit. The overflow water storage tank may be an open or fixed-roof tank provided that a submerged fill pipe (pipe outlet below existing liquid level in the tank) is used to transfer overflow water to the tank. The owner or operator of a delayed coking unit using the ‘‘water overflow’’ method of coke cooling shall determine the coke drum vessel temperature as specified in paragraphs (c) and (d) of this section regardless of the compliance method used to demonstrate compliance with the requirements in paragraph (a) of this section.

(f) The owner or operator of a delayed coking unit may partially drain a coke drum prior to achieving the applicable limits in paragraph (a) of this section in order to double-quench a coke drum that did not cool adequately using the normal cooling process steps provided that the owner or operator meets the conditions in paragraphs (f)(1) and (2) of this section.

(1) The owner or operator shall install, operate, calibrate, and maintain a continuous parameter monitoring system to measure the drain water temperature at the bottom of the coke drum or in the drain line as near as practical to the coke drum according to the requirements specified in table 13 of this subpart.

(2) The owner or operator must maintain the drain water temperature below 210 degrees Fahrenheit during the partial drain associated with the double-quench event.

■ 30. Section 63.658 is added to read as follows:

§ 63.658 Fenceline monitoring provisions.

(a) The owner or operator shall conduct sampling along the facility property boundary and analyze the samples in accordance with Methods 325A and 325B of appendix A of this part and paragraphs (b) through (k) of this section.

(b) The target analyte is benzene.

(c) The owner or operator shall determine passive monitor locations in accordance with Section 8.2 of Method 325A of appendix A of this part.

(1) As it pertains to this subpart, known sources of VOCs, as used in Section 8.2.1.3 in Method 325A of appendix A of this part for siting passive monitors means a wastewater treatment unit, process unit, or any emission source requiring control according to the requirements of this subpart, including marine vessel loading operations. For marine loading operations that are located offshore, one passive monitor should be sited on the shoreline adjacent to the dock.

(2) The owner or operator may collect one or more background samples if the owner or operator believes that an offsite upwind source or an onsite source excluded under § 63.640(g) may influence the sampler measurements. If the owner or operator elects to collect one or more background samples, the owner of operator must develop and submit a site-specific monitoring plan for approval according to the requirements in paragraph (i) of this section. Upon approval of the site-specific monitoring plan, the background sampler(s) should be operated co-currently with the routine samplers.

(3) The owner or operator shall collect at least one co-located duplicate sample for every 10 field samples per sampling period and at least two field blanks per sampling period, as described in Section 9.3 in Method 325A of appendix A of this part. The co-located duplicates may be collected at any one of the perimeter sampling locations.

(4) The owner or operator shall follow the procedure in Section 9.6 of Method 325B of appendix A of this part to determine the detection limit of benzene for each sampler used to collect samples, background samples (if the owner or operator elects to do so), co-located samples and blanks.

(d) The owner or operator shall collect and record meteorological data according to the applicable requirements in paragraphs (d)(1) through (3) of this section.

(1) If a near-field source correction is used as provided in paragraph (i)(1) of this section or if an alternative test method is used that provides time-resolved measurements, the owner or operator shall:

(i) Use an on-site meteorological station in accordance with Section 8.3 of Method 325A of appendix A of this part.

(ii) Collect and record hourly average meteorological data, including temperature, barometric pressure, wind speed and wind direction and calculate daily unit vector wind direction and daily sigma theta.

(2) For cases other than those specified in paragraph (d)(1) of this section, the owner or operator shall collect and record sampling period average temperature and barometric pressure using either an on-site meteorological station in accordance with Section 8.3 of Method 325A of appendix A of this part or, alternatively, using data from a United States Weather Service (USWS) meteorological station provided the USWS meteorological station is within 40 kilometers (25 miles) of the refinery.

(3) If an on-site meteorological station is used, the owner or operator shall follow the calibration and standardization procedures for meteorological measurements in EPA–454/B–08–002 (incorporated by reference—see § 63.14).

(e) The owner of operator shall use a sampling period and sampling frequency as specified in paragraphs (e)(1) through (3) of this section.

(1) *Sampling period.* A 14-day sampling period shall be used, unless a shorter sampling period is determined to be necessary under paragraph (g) or (i) of this section. A sampling period is defined as the period during which sampling tube is deployed at a specific sampling location with the diffusive

sampling end cap in-place and does not include the time required to analyze the sample. For the purpose of this subpart, a 14-day sampling period may be no shorter than 13 calendar days and no longer than 15 calendar days, but the routine sampling period shall be 14 calendar days.

(2) *Base sampling frequency.* Except as provided in paragraph (e)(3) of this section, the frequency of sample collection shall be once each contiguous 14-day sampling period, such that the beginning of the next 14-day sampling period begins immediately upon the completion of the previous 14-day sampling period.

(3) *Alternative sampling frequency for burden reduction.* When an individual monitor consistently achieves results at or below 0.9 $\mu g/m^3$, the owner or operator may elect to use the applicable minimum sampling frequency specified in paragraphs (e)(3)(i) through (v) of this section for that monitoring site. When calculating Δc for the monitoring period when using this alternative for burden reduction, zero shall be substituted for the sample result for the monitoring site for any period where a sample is not taken.

(i) If every sample at a monitoring site is at or below 0.9 $\mu g/m^3$ for 2 years (52 consecutive samples), every other sampling period can be skipped for that monitoring site, *i.e.,* sampling will occur approximately once per month.

(ii) If every sample at a monitoring site that is monitored at the frequency specified in paragraph (e)(3)(i) of this section is at or below 0.9 $\mu g/m^3$ for 2 years (*i.e.,* 26 consecutive ''monthly'' samples), five 14-day sampling periods can be skipped for that monitoring site following each period of sampling, *i.e.,* sampling will occur approximately once per quarter.

(iii) If every sample at a monitoring site that is monitored at the frequency specified in paragraph (e)(3)(ii) of this section is at or below 0.9 $\mu g/m^3$ for 2 years (*i.e.,* 8 consecutive quarterly samples), twelve 14-day sampling periods can be skipped for that monitoring site following each period of sampling, *i.e.,* sampling will occur twice a year.

(iv) If every sample at a monitoring site that is monitored at the frequency specified in paragraph (e)(3)(iii) of this section is at or below 0.9 $\mu g/m^3$ for an 2 years (*i.e.,* 4 consecutive semi-annual samples), only one sample per year is required for that monitoring site. For yearly sampling, samples shall occur at least 10 months but no more than 14 months apart.

(v) If at any time a sample for a monitoring site that is monitored at the frequency specified in paragraphs (e)(3)(i) through (iv) of this section returns a result that is above 0.9 $\mu g/m^3$, the sampling site must return to the original sampling requirements of contiguous 14-day sampling periods with no skip periods for one quarter (six 14-day sampling periods). If every sample collected during this quarter is at or below 0.9 $\mu g/m^3$, the owner or operator may revert back to the reduced monitoring schedule applicable for that monitoring site prior to the sample reading exceeding 0.9 $\mu g/m^3$ If any sample collected during this quarter is above 0.9 $\mu g/m^3$, that monitoring site must return to the original sampling requirements of contiguous 14-day sampling periods with no skip periods for a minimum of two years. The burden reduction requirements can be used again for that monitoring site once the requirements of paragraph (e)(3)(i) of this section are met again, *i.e.,* after 52 contiguous 14-day samples with no results above 0.9 $\mu g/m^3$.

(f) Within 45 days of completion of each sampling period, the owner or operator shall determine whether the results are above or below the action level as follows:

(1) The owner or operator shall determine the facility impact on the benzene concentration (Δc) for each 14-day sampling period according to either paragraph (f)(1)(i) or (ii) of this section, as applicable.

(i) Except when near-field source correction is used as provided in paragraph (i) of this section, the owner or operator shall determine the highest and lowest sample results for benzene concentrations from the sample pool and calculate Δc as the difference in these concentrations. The owner or operator shall adhere to the following procedures when one or more samples for the sampling period are below the method detection limit for benzene:

(A) If the lowest detected value of benzene is below detection, the owner or operator shall use zero as the lowest sample result when calculating Δc.

(B) If all sample results are below the method detection limit, the owner or operator shall use the method detection limit as the highest sample result.

(ii) When near-field source correction is used as provided in paragraph (i) of this section, the owner or operator shall determine Δc using the calculation protocols outlined in the approved site-specific monitoring plan and in paragraph (i) of this section.

(2) The owner or operator shall calculate the annual average Δc based on the average of the 26 most recent 14-day sampling periods. The owner or operator shall update this annual average value after receiving the results of each subsequent 14-day sampling period.

(3) The action level for benzene is 9 micrograms per cubic meter (μg/m3) on an annual average basis. If the annual average Δc value for benzene is less than or equal to 9 $\mu g/m^3$, the concentration is below the action level. If the annual average Δc value for benzene is greater than 9 $\mu g/m^3$, the concentration is above the action level, and the owner or operator shall conduct a root cause analysis and corrective action in accordance with paragraph (g) of this section.

(g) Within 5 days of determining that the action level has been exceeded for any annual average Δc and no longer than 50 days after completion of the sampling period, the owner or operator shall initiate a root cause analysis to determine the cause of such exceedance and to determine appropriate corrective action, such as those described in paragraphs (g)(1) through (4) of this section. The root cause analysis and initial corrective action analysis shall be completed and initial corrective actions taken no later than 45 days after determining there is an exceedance. Root cause analysis and corrective action may include, but is not limited to:

(1) Leak inspection using Method 21 of part 60, appendix A–7 of this chapter and repairing any leaks found.

(2) Leak inspection using optical gas imaging and repairing any leaks found.

(3) Visual inspection to determine the cause of the high benzene emissions and implementing repairs to reduce the level of emissions.

(4) Employing progressively more frequent sampling, analysis and meteorology (*e.g.,* using shorter sampling periods for Methods 325A and 325B of appendix A of this part, or using active sampling techniques).

(h) If, upon completion of the corrective action analysis and corrective actions such as those described in paragraph (g) of this section, the Δc value for the next 14-day sampling period for which the sampling start time begins after the completion of the corrective actions is greater than 9 $\mu g/m^3$ or if all corrective action measures identified require more than 45 days to implement, the owner or operator shall develop a corrective action plan that describes the corrective action(s) completed to date, additional measures that the owner or operator proposes to employ to reduce fenceline concentrations below the action level, and a schedule for completion of these measures. The owner or operator shall submit the corrective action plan to the

Administrator within 60 days after receiving the analytical results indicating that the Δc value for the 14-day sampling period following the completion of the initial corrective action is greater than 9 μg/m³ or, if no initial corrective actions were identified, no later than 60 days following the completion of the corrective action analysis required in paragraph (g) of this section.

(i) An owner or operator may request approval from the Administrator for a site-specific monitoring plan to account for offsite upwind sources or onsite sources excluded under § 63.640(g) according to the requirements in paragraphs (i)(1) through (4) of this section.

(1) The owner or operator shall prepare and submit a site-specific monitoring plan and receive approval of the site-specific monitoring plan prior to using the near-field source alternative calculation for determining Δc provided in paragraph (i)(2) of this section. The site-specific monitoring plan shall include, at a minimum, the elements specified in paragraphs (i)(1)(i) through (v) of this section. The procedures in Section 12 of Method 325A of appendix A of this part are not required, but may be used, if applicable, when determining near-field source contributions.

(i) Identification of the near-field source or sources. For onsite sources, documentation that the onsite source is excluded under § 63.640(g) and identification of the specific provision in § 63.640(g) that applies to the source.

(ii) Location of the additional monitoring stations that shall be used to determine the uniform background concentration and the near-field source concentration contribution.

(iii) Identification of the fenceline monitoring locations impacted by the near-field source. If more than one near-field source is present, identify the near-field source or sources that are expected to contribute to the concentration at that monitoring location.

(iv) A description of (including sample calculations illustrating) the planned data reduction and calculations to determine the near-field source concentration contribution for each monitoring location.

(v) If more frequent monitoring or a monitoring station other than a passive diffusive tube monitoring station is proposed, provide a detailed description of the measurement methods, measurement frequency, and recording frequency for determining the uniform background or near-field source concentration contribution.

(2) When an approved site-specific monitoring plan is used, the owner or operator shall determine Δc for comparison with the 9 μg/m³ action level using the requirements specified in paragraphs (i)(2)(i) through (iii) of this section.

(i) For each monitoring location, calculate Δc_i using the following equation.

$$\Delta c_i = MFC_i - NFS_i - UB$$

Where:

Δc_i = The fenceline concentration, corrected for background, at measurement location i, micrograms per cubic meter (μg/m³).

MFC_i = The measured fenceline concentration at measurement location i, μg/m³.

NFS_i = The near-field source contributing concentration at measurement location i determined using the additional measurements and calculation procedures included in the site-specific monitoring plan, μg/m³. For monitoring locations that are not included in the site-specific monitoring plan as impacted by a near-field source, use NFS_i = 0 μg/m³.

UB = The uniform background concentration determined using the additional measurements included in the site-specific monitoring plan, μg/m³. If no additional measurements are specified in the site-specific monitoring plan for determining the uniform background concentration, use UB = 0 μg/m³.

(ii) When one or more samples for the sampling period are below the method detection limit for benzene, adhere to the following procedures:

(A) If the benzene concentration at the monitoring location used for the uniform background concentration is below the method detection limit, the owner or operator shall use zero for UB for that monitoring period.

(B) If the benzene concentration at the monitoring location(s) used to determine the near-field source contributing concentration is below the method detection limit, the owner or operator shall use zero for the monitoring location concentration when calculating NFS_i for that monitoring period.

(C) If a fenceline monitoring location sample result is below the method detection limit, the owner or operator shall use the method detection limit as the sample result.

(iii) Determine Δc for the monitoring period as the maximum value of Δc_i from all of the fenceline monitoring locations for that monitoring period.

(3) The site-specific monitoring plan shall be submitted and approved as described in paragraphs (i)(3)(i) through (iv) of this section.

(i) The site-specific monitoring plan must be submitted to the Administrator for approval.

(ii) The site-specific monitoring plan shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143–01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refineryrtr@epa.gov.*

(iii) The Administrator shall approve or disapprove the plan in 90 days. The plan shall be considered approved if the Administrator either approves the plan in writing, or fails to disapprove the plan in writing. The 90-day period shall begin when the Administrator receives the plan.

(iv) If the Administrator finds any deficiencies in the site-specific monitoring plan and disapproves the plan in writing, the owner or operator may revise and resubmit the site-specific monitoring plan following the requirements in paragraphs (i)(3)(i) and (ii) of this section. The 90-day period starts over with the resubmission of the revised monitoring plan.

(4) The approval by the Administrator of a site-specific monitoring plan will be based on the completeness, accuracy and reasonableness of the request for a site-specific monitoring plan. Factors that the Administrator will consider in reviewing the request for a site-specific monitoring plan include, but are not limited to, those described in paragraphs (i)(4)(i) through (v) of this section.

(i) The identification of the near-field source or sources. For onsite sources, the documentation provided that the onsite source is excluded under § 63.640(g).

(ii) The monitoring location selected to determine the uniform background concentration or an indication that no uniform background concentration monitor will be used.

(iii) The location(s) selected for additional monitoring to determine the near-field source concentration contribution.

(iv) The identification of the fenceline monitoring locations impacted by the near-field source or sources.

(v) The appropriateness of the planned data reduction and calculations to determine the near-field source concentration contribution for each monitoring location.

(vi) If more frequent monitoring is proposed, the adequacy of the description of the measurement and recording frequency proposed and the adequacy of the rationale for using the alternative monitoring frequency.

(j) The owner or operator shall comply with the applicable recordkeeping and reporting requirements in § 63.655(h) and (i).

(k) As outlined in § 63.7(f), the owner or operator may submit a request for an alternative test method. At a minimum, the request must follow the requirements outlined in paragraphs (k)(1) through (7) of this section.

(1) The alternative method may be used in lieu of all or a partial number of passive samplers required in Method 325A of appendix A of this part.

(2) The alternative method must be validated according to Method 301 in appendix A of this part or contain performance based procedures and indicators to ensure self-validation.

(3) The method detection limit must nominally be at least an order of magnitude below the action level, *i.e.,* 0.9 $\mu g/m^3$ benzene. The alternate test method must describe the procedures used to provide field verification of the detection limit.

(4) The spatial coverage must be equal to or better than the spatial coverage provided in Method 325A of appendix A of this part.

(i) For path average concentration open-path instruments, the physical path length of the measurement shall be no more than a passive sample footprint (the spacing that would be provided by the sorbent traps when following Method 325A). For example, if Method 325A requires spacing monitors A and B 610 meters (2000 feet) apart, then the physical path length limit for the measurement at that portion of the fenceline shall be no more than 610 meters (2000 feet).

(ii) For range resolved open-path instrument or approach, the instrument or approach must be able to resolve an average concentration over each passive sampler footprint within the path length of the instrument.

(iii) The extra samplers required in Sections 8.2.1.3 of Method 325A may be omitted when they fall within the path length of an open-path instrument.

(5) At a minimum, non-integrating alternative test methods must provide a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(6) For alternative test methods capable of real time measurements (less than a 5 minute sampling and analysis cycle), the alternative test method may allow for elimination of data points corresponding to outside emission sources for purpose of calculation of the high point for the two week average. The alternative test method approach must have wind speed, direction and stability class of the same time resolution and within the footprint of the instrument.

(7) For purposes of averaging data points to determine the Δc for the 14-day average high sample result, all results measured under the method detection limit must use the method detection limit. For purposes of averaging data points for the 14-day average low sample result, all results measured under the method detection limit must use zero.

■ 31. Section 63.660 is added to read as follows:

§ 63.660 Storage vessel provisions.

On and after the applicable compliance date for a Group 1 storage vessel located at a new or existing source as specified in § 63.640(h), the owner or operator of a Group 1 storage vessel that is part of a new or existing source shall comply with the requirements in subpart WW or SS of this part according to the requirements in paragraphs (a) through (i) of this section.

(a) As used in this section, all terms not defined in § 63.641 shall have the meaning given them in subpart A, WW, or SS of this part. The definitions of ‘‘Group 1 storage vessel’’ (paragraph (2)) and ‘‘Storage vessel’’ in § 63.641 shall apply in lieu of the definition of ‘‘Storage vessel’’ in § 63.1061.

(1) An owner or operator may use good engineering judgment or test results to determine the stored liquid weight percent total organic HAP for purposes of group determination. Data, assumptions, and procedures used in the determination shall be documented.

(2) When an owner or operator and the Administrator do not agree on whether the annual average weight percent organic HAP in the stored liquid is above or below 4 percent for a storage vessel at an existing source or above or below 2 percent for a storage vessel at a new source, an appropriate method (based on the type of liquid stored) as published by EPA or a consensus-based standards organization shall be used. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, *http://www.astm.org*), the American National Standards Institute (ANSI, 1819 L Street NW., 6th Floor, Washington, DC 20036, (202) 293–8020, *http://www.ansi.org*), the American Gas Association (AGA, 400 North Capitol Street NW., 4th Floor, Washington, DC 20001, (202) 824–7000, *http://www.aga.org*), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, *http://www.asme.org*), the American Petroleum Institute (API, 1220 L Street NW., Washington, DC 20005–4070, (202) 682–8000, *http://www.api.org*), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356–0060, *http://www.naesb.org*).

(b) A floating roof storage vessel complying with the requirements of subpart WW of this part may comply with the control option specified in paragraph (b)(1) of this section and, if equipped with a ladder having at least one slotted leg, shall comply with one of the control options as described in paragraph (b)(2) of this section.

(1) In addition to the options presented in §§ 63.1063(a)(2)(viii)(A) and (B) and 63.1064, a floating roof storage vessel may comply with § 63.1063(a)(2)(vii) using a flexible enclosure device and either a gasketed or welded cap on the top of the guidepole.

(2) Each opening through a floating roof for a ladder having at least one slotted leg shall be equipped with one of the configurations specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) A pole float in the slotted leg and pole wipers for both legs. The wiper or seal of the pole float must be at or above the height of the pole wiper.

(ii) A ladder sleeve and pole wipers for both legs of the ladder.

(iii) A flexible enclosure device and either a gasketed or welded cap on the top of the slotted leg.

(c) For the purposes of this subpart, references shall apply as specified in paragraphs (c)(1) through (6) of this section.

(1) All references to ‘‘the proposal date for a referencing subpart’’ and ‘‘the proposal date of the referencing subpart’’ in subpart WW of this part mean June 30, 2014.

(2) All references to ‘‘promulgation of the referencing subpart’’ and ‘‘the promulgation date of the referencing subpart’’ in subpart WW of this part mean February 1, 2016.

(3) All references to ‘‘promulgation date of standards for an affected source or affected facility under a referencing subpart’’ in subpart SS of this part mean February 1, 2016.

(4) All references to ‘‘the proposal date of the relevant standard established pursuant to CAA section 112(f)’’ in

subpart SS of this part mean June 30, 2014.

(5) All references to ''the proposal date of a relevant standard established pursuant to CAA section 112(d)'' in subpart SS of this part mean July 14, 1994.

(6) All references to the ''required control efficiency'' in subpart SS of this part mean reduction of organic HAP emissions by 95 percent or to an outlet concentration of 20 ppmv.

(d) For an uncontrolled fixed roof storage vessel that commenced construction on or before June 30, 2014, and that meets the definition of ''Group 1 storage vessel'', paragraph (2), in § 63.641 but not the definition of ''Group 1 storage vessel'', paragraph (1), in § 63.641, the requirements of § 63.982 and/or § 63.1062 do not apply until the next time the storage vessel is completely emptied and degassed, or January 30, 2026, whichever occurs first.

(e) Failure to perform inspections and monitoring required by this section shall constitute a violation of the applicable standard of this subpart.

(f) References in § 63.1066(a) to initial startup notification requirements do not apply.

(g) References to the Notification of Compliance Status in § 63.999(b) mean the Notification of Compliance Status required by § 63.655(f).

(h) References to the Periodic Reports in §§ 63.1066(b) and 63.999(c) mean the Periodic Report required by § 63.655(g).

(i) Owners or operators electing to comply with the requirements in subpart SS of this part for a Group 1 storage vessel must comply with the requirements in paragraphs (i)(1) through (3) of this section.

(1) If a flare is used as a control device, the flare shall meet the requirements of § 63.670 instead of the flare requirements in § 63.987.

(2) If a closed vent system contains a bypass line, the owner or operator shall comply with the provisions of either § 63.983(a)(3)(i) or (ii) for each closed vent system that contains bypass lines that could divert a vent stream either directly to the atmosphere or to a control device that does not comply with the requirements in subpart SS of this part. Except as provided in paragraphs (i)(2)(i) and (ii) of this section, use of the bypass at any time to divert a Group 1 storage vessel to either directly to the atmosphere or to a control device that does not comply with the requirements in subpart SS of this part is an emissions standards violation. Equipment such as low leg drains and equipment subject to § 63.648 are not subject to this paragraph (i)(2).

(i) If planned routine maintenance of the control device cannot be performed during periods that storage vessel emissions are vented to the control device or when the storage vessel is taken out of service for inspections or other planned maintenance reasons, the owner or operator may bypass the control device.

(ii) Periods for which storage vessel control device may be bypassed for planned routine maintenance of the control device shall not exceed 240 hours per calendar year.

(3) If storage vessel emissions are routed to a fuel gas system or process, the fuel gas system or process shall be operating at all times when regulated emissions are routed to it. The exception in § 63.984(a)(1) does not apply.

■ 32. Section 63.670 is added to read as follows:

§ 63.670 Requirements for flare control devices.

On or before January 30, 2019, the owner or operator of a flare used as a control device for an emission point subject to this subpart shall meet the applicable requirements for flares as specified in paragraphs (a) through (q) of this section and the applicable requirements in § 63.671. The owner or operator may elect to comply with the requirements of paragraph (r) of this section in lieu of the requirements in paragraphs (d) through (f) of this section, as applicable.

(a) [Reserved]

(b) *Pilot flame presence.* The owner or operator shall operate each flare with a pilot flame present at all times when regulated material is routed to the flare. Each 15-minute block during which there is at least one minute where no pilot flame is present when regulated material is routed to the flare is a deviation of the standard. Deviations in different 15-minute blocks from the same event are considered separate deviations. The owner or operator shall monitor for the presence of a pilot flame as specified in paragraph (g) of this section.

(c) *Visible emissions.* The owner or operator shall specify the smokeless design capacity of each flare and operate with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, when regulated material is routed to the flare and the flare vent gas flow rate is less than the smokeless design capacity of the flare. The owner or operator shall monitor for visible emissions from the flare as specified in paragraph (h) of this section.

(d) *Flare tip velocity.* For each flare, the owner or operator shall comply with either paragraph (d)(1) or (2) of this section, provided the appropriate monitoring systems are in-place, whenever regulated material is routed to the flare for at least 15-minutes and the flare vent gas flow rate is less than the smokeless design capacity of the flare.

(1) Except as provided in paragraph (d)(2) of this section, the actual flare tip velocity (V_{tip}) must be less than 60 feet per second. The owner or operator shall monitor V_{tip} using the procedures specified in paragraphs (i) and (k) of this section.

(2) V_{tip} must be less than 400 feet per second and also less than the maximum allowed flare tip velocity (V_{max}) as calculated according to the following equation. The owner or operator shall monitor Vtip using the procedures specified in paragraphs (i) and (k) of this section and monitor gas composition and determine NHV_{vg} using the procedures specified in paragraphs (j) and (l) of this section.

$$Log_{10}(V_{max}) = \frac{NHV_{vg} + 1{,}212}{850}$$

Where:

V_{max} = Maximum allowed flare tip velocity, ft/sec.

NHV_{vg} = Net heating value of flare vent gas, as determined by paragraph (l)(4) of this section, Btu/scf.

1,212 = Constant.

850 = Constant.

(e) *Combustion zone operating limits.* For each flare, the owner or operator shall operate the flare to maintain the net heating value of flare combustion zone gas (NHV_{cz}) at or above 270 British thermal units per standard cubic feet (Btu/scf) determined on a 15-minute block period basis when regulated material is routed to the flare for at least 15-minutes. The owner or operator shall monitor and calculate NHV_{cz} as specified in paragraph (m) of this section.

(f) *Dilution operating limits for flares with perimeter assist air.* For each flare actively receiving perimeter assist air, the owner or operator shall operate the flare to maintain the net heating value dilution parameter (NHVdil) at or above 22 British thermal units per square foot (Btu/ft^2) determined on a 15-minute block period basis when regulated material is being routed to the flare for at least 15-minutes. The owner or operator shall monitor and calculate NHV_{dil} as specified in paragraph (n) of this section.

(g) *Pilot flame monitoring.* The owner or operator shall continuously monitor the presence of the pilot flame(s) using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame(s) is present.

(h) *Visible emissions monitoring.* The owner or operator shall monitor visible emissions while regulated materials are vented to the flare. An initial visible emissions demonstration must be conducted using an observation period of 2 hours using Method 22 at 40 CFR part 60, appendix A–7. Subsequent visible emissions observations must be conducted using either the methods in paragraph (h)(1) of this section or, alternatively, the methods in paragraph (h)(2) of this section. The owner or operator must record and report any instances where visible emissions are observed for more than 5 minutes during any 2 consecutive hours as specified in § 63.655(g)(11)(ii).

(1) At least once per day, conduct visible emissions observations using an observation period of 5 minutes using Method 22 at 40 CFR part 60, appendix A–7. If at any time the owner or operator sees visible emissions, even if the minimum required daily visible emission monitoring has already been performed, the owner or operator shall immediately begin an observation period of 5 minutes using Method 22 at 40 CFR part 60, appendix A–7. If visible emissions are observed for more than one continuous minute during any 5-minute observation period, the observation period using Method 22 at 40 CFR part 60, appendix A–7 must be extended to 2 hours or until 5-minutes of visible emissions are observed.

(2) Use a video surveillance camera to continuously record (at least one frame every 15 seconds with time and date stamps) images of the flare flame and a reasonable distance above the flare flame at an angle suitable for visual emissions observations. The owner or operator must provide real-time video surveillance camera output to the control room or other continuously manned location where the camera images may be viewed at any time.

(i) *Flare vent gas, steam assist and air assist flow rate monitoring.* The owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate in the flare header or headers that feed the flare as well as any supplemental natural gas used. Different flow monitoring methods may be used to measure different gaseous streams that make up the flare vent gas provided that the flow rates of all gas streams that contribute to the flare vent gas are determined. If assist air or assist steam is used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of assist air and/or assist steam used with the flare. If pre-mix assist air and perimeter assist are both used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of separately measuring, calculating, and recording the volumetric flow rate of premix assist air and perimeter assist air used with the flare. Continuously monitoring fan speed or power and using fan curves is an acceptable method for continuously monitoring assist air flow rates.

(1) The flow rate monitoring systems must be able to correct for the temperature and pressure of the system and output parameters in standard conditions (*i.e.,* a temperature of 20 °C (68 °F) and a pressure of 1 atmosphere).

(2) Mass flow monitors may be used for determining volumetric flow rate of flare vent gas provided the molecular weight of the flare vent gas is determined using compositional analysis as specified in paragraph (j) of this section so that the mass flow rate can be converted to volumetric flow at standard conditions using the following equation.

$$Q_{vol} = \frac{Q_{mass} \times 385.3}{MWt}$$

Where:

Q_{vol} = Volumetric flow rate, standard cubic feet per second.

Q_{mass} = Mass flow rate, pounds per second.

385.3 = Conversion factor, standard cubic feet per pound-mole.

MWt = Molecular weight of the gas at the flow monitoring location, pounds per pound-mole.

(3) Mass flow monitors may be used for determining volumetric flow rate of assist air or assist steam. Use equation in paragraph (i)(2) of this section to convert mass flow rates to volumetric flow rates. Use a molecular weight of 18 pounds per pound-mole for assist steam and use a molecular weight of 29 pounds per pound-mole for assist air.

(4) Continuous pressure/temperature monitoring system(s) and appropriate engineering calculations may be used in lieu of a continuous volumetric flow monitoring systems provided the molecular weight of the gas is known. For assist steam, use a molecular weight of 18 pounds per pound-mole. For assist air, use a molecular weight of 29 pounds per pound-mole. For flare vent gas, molecular weight must be determined using compositional analysis as specified in paragraph (j) of this section.

(j) *Flare vent gas composition monitoring.* The owner or operator shall determine the concentration of individual components in the flare vent gas using either the methods provided in paragraph (j)(1) or (2) of this section, to assess compliance with the operating limits in paragraph (e) of this section and, if applicable, paragraphs (d) and (f) of this section. Alternatively, the owner or operator may elect to directly monitor the net heating value of the flare vent gas following the methods provided in paragraphs (j)(3) of this section and, if desired, may directly measure the hydrogen concentration in the flare vent gas following the methods provided in paragraphs (j)(4) of this section. The owner or operator may elect to use different monitoring methods for different gaseous streams that make up the flare vent gas using different methods provided the composition or net heating value of all gas streams that contribute to the flare vent gas are determined.

(1) Except as provided in paragraphs (j)(5) and (6) of this section, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring (*i.e.,* at least once every 15-minutes), calculating, and recording the individual component concentrations present in the flare vent gas.

(2) Except as provided in paragraphs (j)(5) and (6) of this section, the owner or operator shall install, operate, and maintain a grab sampling system capable of collecting an evacuated canister sample for subsequent compositional analysis at least once every eight hours while there is flow of regulated material to the flare. Subsequent compositional analysis of the samples must be performed according to Method 18 of 40 CFR part 60, appendix A–6, ASTM D6420–99 (Reapproved 2010), ASTM D1945–03 (Reapproved 2010), ASTM D1945–14 or ASTM UOP539–12 (all incorporated by reference—see § 63.14).

(3) Except as provided in paragraphs (j)(5) and (6) of this section, the owner or operator shall install, operate, calibrate, and maintain a calorimeter capable of continuously measuring, calculating, and recording NHV_{vg} at standard conditions.

(4) If the owner or operator uses a continuous net heating value monitor according to paragraph (j)(3) of this section, the owner or operator may, at their discretion, install, operate, calibrate, and maintain a monitoring

system capable of continuously measuring, calculating, and recording the hydrogen concentration in the flare vent gas.

(5) Direct compositional or net heating value monitoring is not required for purchased (''pipeline quality'') natural gas streams. The net heating value of purchased natural gas streams may be determined using annual or more frequent grab sampling at any one representative location. Alternatively, the net heating value of any purchased natural gas stream can be assumed to be 920 Btu/scf.

(6) Direct compositional or net heating value monitoring is not required for gas streams that have been demonstrated to have consistent composition (or a fixed minimum net heating value) according to the methods in paragraphs (j)(6)(i) through (v) of this section.

(i) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(A) A description of the flare gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the flare gas stream/system and the affected flare(s) to be considered;

(B) A statement that there are no crossover or entry points to be introduced into the flare gas stream/system (this should be shown in the piping diagrams) prior to the point where the flow rate of the gas streams is measured;

(C) An explanation of the conditions that ensure that the flare gas net heating value is consistent and, if flare gas net heating value is expected to vary (*e.g.,* due to product loading of different material), the conditions expected to produce the flare gas with the lowest net heating value;

(D) The supporting test results from sampling the requested flare gas stream/system for the net heating value. Sampling data must include, at minimum, 2 weeks of daily measurement values (14 grab samples) for frequently operated flare gas streams/systems; for infrequently operated flare gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. If the flare gas stream composition can vary, samples must be taken during those conditions expected to result in lowest net heating value identified in paragraph (j)(6)(i)(C) of this section. The owner or operator shall determine net heating value for the gas stream using either gas composition analysis or net heating value monitor (with optional hydrogen concentration analyzer) according to the method provided in paragraph (l) of this section; and

(E) A description of how the 2 weeks (or seven samples for infrequently operated flare gas streams/systems) of monitoring results compares to the typical range of net heating values expected for the flare gas stream/system going to the affected flare (*e.g.,* ''the samples are representative of typical operating conditions of the flare gas stream going to the loading rack flare'' or ''the samples are representative of conditions expected to yield the lowest net heating value of the flare gas stream going to the loading rack flare'').

(F) The net heating value to be used for all flows of the flare vent gas from the flare gas stream/system covered in the application. A single net heating value must be assigned to the flare vent gas either by selecting the lowest net heating value measured in the sampling program or by determining the 95th percent confidence interval on the mean value of all samples collected using the t-distribution statistic (which is 1.943 for 7 grab samples or 1.771 for 14 grab samples).

(ii) The effective date of the exemption is the date of submission of the information required in paragraph (j)(6)(i) of this section.

(iii) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (*e.g.,* the stream composition changes). If such a change occurs, the owner or operator shall follow the procedures in paragraph (j)(6)(iii)(A), (B), or (C) of this section.

(A) If the operation change results in a flare vent gas net heating value that is still within the range of net heating values included in the original application, the owner or operator shall determine the net heating value on a grab sample and record the results as proof that the net heating value assigned to the vent gas stream in the original application is still appropriate.

(B) If the operation change results in a flare vent gas net heating value that is lower than the net heating value assigned to the vent gas stream in the original application, the owner or operator may submit new information following the procedures of paragraph (j)(6)(i) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(C) If the operation change results in a flare vent gas net heating value has greater variability in the flare gas stream/system such the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin monitoring the composition or net heat content of the flare vent gas stream using the methods in this section (*i.e.,* grab samples every 8 hours until such time a continuous monitor, if elected, is installed).

(k) *Calculation methods for cumulative flow rates and determining compliance with Vtip operating limits*. The owner or operator shall determine V_{tip} on a 15-minute block average basis according to the following requirements.

(1) The owner or operator shall use design and engineering principles to determine the unobstructed cross sectional area of the flare tip. The unobstructed cross sectional area of the flare tip is the total tip area that vent gas can pass through. This area does not include any stability tabs, stability rings, and upper steam or air tubes because flare vent gas does not exit through them.

(2) The owner or operator shall determine the cumulative volumetric flow of flare vent gas for each 15-minute block average period using the data from the continuous flow monitoring system required in paragraph (i) of this section according to the following requirements, as applicable. If desired, the cumulative flow rate for a 15-minute block period only needs to include flow during those periods when regulated material is sent to the flare, but owners or operators may elect to calculate the cumulative flow rates across the entire 15-minute block period for any 15-minute block period where there is regulated material flow to the flare.

(i) Use set 15-minute time periods starting at 12 midnight to 12:15 a.m., 12:15 a.m. to 12:30 a.m. and so on concluding at 11:45 p.m. to midnight when calculating 15-minute block average flow volumes.

(ii) If continuous pressure/temperature monitoring system(s) and engineering calculations are used as allowed under paragraph (i)(4) of this section, the owner or operator shall, at a minimum, determine the 15-minute block average temperature and pressure from the monitoring system and use those values to perform the engineering calculations to determine the cumulative flow over the 15-minute block average period. Alternatively, the owner or operator may divide the 15-minute block average period into equal duration subperiods (*e.g.*, three 5-minute periods) and determine the average temperature and pressure for each subperiod, perform engineering calculations to determine the flow for each subperiod, then add the volumetric flows for the subperiods to determine the cumulative volumetric flow of vent gas for the 15-minute block average period.

(3) The 15-minute block average V_{tip} shall be calculated using the following equation.

$$V_{tip} = \frac{Q_{cum}}{Area \times 900}$$

Where:

V_{tip} = Flare tip velocity, feet per second.
Q_{cum} = Cumulative volumetric flow over 15-minute block average period, actual cubic feet.
Area = Unobstructed area of the flare tip, square feet.
900 = Conversion factor, seconds per 15-minute block average.

(4) If the owner or operator chooses to comply with paragraph (d)(2) of this section, the owner or operator shall also determine the net heating value of the flare vent gas following the requirements in paragraphs (j) and (l) of this section and calculate V_{max} using the equation in paragraph (d)(2) of this section in order to compare V_{tip} to V_{max} on a 15-minute block average basis.

(l) *Calculation methods for determining flare vent gas net heating value.* The owner or operator shall determine the net heating value of the flare vent gas (NHV_{vg}) based on the composition monitoring data on a 15-minute block average basis according to the following requirements.

(1) If compositional analysis data are collected as provided in paragraph (j)(1) or (2) of this section, the owner or operator shall determine NHV_{vg} of a specific sample by using the following equation.

$$NHV_{vg} = \sum_{i=1}^{n} x_i NHV_i$$

Where:

NHV_{vg} = Net heating value of flare vent gas, Btu/scf.
i = Individual component in flare vent gas.
n = Number of components in flare vent gas.
x_i = Concentration of component i in flare vent gas, volume fraction.
NHV_i = Net heating value of component i according to table 12 of this subpart, Btu/scf. If the component is not specified in table 12 of this subpart, the heats of combustion may be determined using any published values where the net enthalpy per mole of offgas is based on combustion at 25 °C and 1 atmosphere (or constant pressure) with offgas water in the gaseous state, but the standard temperature for determining the volume corresponding to one mole of vent gas is 20 °C.

(2) If direct net heating value monitoring data are collected as provided in paragraph (j)(3) of this section but a hydrogen concentration monitor is not used, the owner or operator shall use the direct output of the monitoring system(s) (in Btu/scf) to determine the NHV_{vg} for the sample.

(3) If direct net heating value monitoring data are collected as provided in paragraph (j)(3) of this section and hydrogen concentration monitoring data are collected as provided in paragraph (j)(4) of this section, the owner or operator shall use the following equation to determine NHV_{vg} for each sample measured via the net heating value monitoring system.

$$NHV_{vg} = NHV_{measured} + 938x_{H2}$$

Where:

NHV_{vg} = Net heating value of flare vent gas, Btu/scf.
$NHV_{measured}$ = Net heating value of flare vent gas stream as measured by the continuous net heating value monitoring system, Btu/scf.
x_{H2} = Concentration of hydrogen in flare vent gas at the time the sample was input into the net heating value monitoring system, volume fraction.
938 = Net correction for the measured heating value of hydrogen (1,212 − 274), Btu/scf.

(4) Use set 15-minute time periods starting at 12 midnight to 12:15 a.m., 12:15 a.m. to 12:30 a.m. and so on concluding at 11:45 p.m. to midnight when calculating 15-minute block averages.

(5) When a continuous monitoring system is used as provided in paragraph (j)(1) or (3) of this section and, if applicable, paragraph (j)(4) of this section, the owner or operator may elect to determine the 15-minute block average NHV_{vg} using either the calculation methods in paragraph (l)(5)(i) of this section or the calculation methods in paragraph (l)(5)(ii) of this section. The owner or operator may choose to comply using the calculation methods in paragraph (l)(5)(i) of this section for some flares at the petroleum refinery and comply using the calculation methods (l)(5)(ii) of this section for other flares. However, for each flare, the owner or operator must elect one calculation method that will apply at all times, and use that method for all continuously monitored flare vent streams associated with that flare. If the owner or operator intends to change the calculation method that applies to a flare, the owner or operator must notify the Administrator 30 days in advance of such a change.

(i) *Feed-forward calculation method.* When calculating NHV_{vg} for a specific 15-minute block:

(A) Use the results from the first sample collected during an event, (for periodic flare vent gas flow events) for the first 15-minute block associated with that event.

(B) If the results from the first sample collected during an event (for periodic flare vent gas flow events) are not available until after the second 15-minute block starts, use the results from the first sample collected during an event for the second 15-minute block associated with that event.

(C) For all other cases, use the results that are available from the most recent sample prior to the 15-minute block period for that 15-minute block period for all flare vent gas steams. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 a.m. and the analysis is completed at 12:38 a.m., the results are available at 12:38 a.m. and these results would be used to determine compliance during the 15-minute block period from 12:45 a.m. to 1:00 a.m.

(ii) *Direct calculation method.* When calculating NHV_{vg} for a specific 15-minute block:

(A) If the results from the first sample collected during an event (for periodic flare vent gas flow events) are not available until after the second 15-minute block starts, use the results from the first sample collected during an event for the first 15-minute block associated with that event.

(B) For all other cases, use the arithmetic average of all NHV_{vg} measurement data results that become available during a 15-minute block to calculate the 15-minute block average for that period. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 a.m. and the analysis is completed at 12:38 a.m., the results are available at 12:38 a.m. and these results would be used to determine compliance during the 15-minute block period from 12:30 a.m. to 12:45 a.m.

(6) When grab samples are used to determine flare vent gas composition:

(i) Use the analytical results from the first grab sample collected for an event for all 15-minute periods from the start of the event through the 15-minute block prior to the 15-minute block in which a subsequent grab sample is collected.

(ii) Use the results from subsequent grab sampling events for all 15 minute periods starting with the 15-minute block in which the sample was collected and ending with the 15-minute block prior to the 15-minute block in which the next grab sample is collected. For the purpose of this requirement, use the time the sample was collected rather than the time the analytical results become available.

(7) If the owner or operator monitors separate gas streams that combine to comprise the total flare vent gas flow, the 15-minute block average net heating value shall be determined separately for each measurement location according to the methods in paragraphs (l)(1) through (6) of this section and a flow-weighted average of the gas stream net heating values shall be used to determine the 15-minute block average net heating value of the cumulative flare vent gas.

(m) *Calculation methods for determining combustion zone net heating value.* The owner or operator shall determine the net heating value of the combustion zone gas (NHV_{cz}) as specified in paragraph (m)(1) or (2) of this section, as applicable.

(1) Except as specified in paragraph (m)(2) of this section, determine the 15-minute block average NHV_{cz} based on the 15-minute block average vent gas and assist gas flow rates using the following equation. For periods when there is no assist steam flow or premix assist air flow, $NHV_{cz} = NHV_{vg}$.

$$NHV_{cz} = \frac{Q_{vg} \times NHV_{vg}}{\left(Q_{vg} + Q_s + Q_{a,premix}\right)}$$

Where:

NHV_{cz} = Net heating value of combustion zone gas, Btu/scf.

NHV_{vg} = Net heating value of flare vent gas for the 15-minute block period, Btu/scf.

Q_{vg} = Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

(2) Owners or operators of flares that use the feed-forward calculation methodology in paragraph (l)(5)(i) of this section and that monitor gas composition or net heating value in a location representative of the cumulative vent gas stream and that directly monitor supplemental natural gas flow additions to the flare must determine the 15-minute block average NHV_{cz} using the following equation.

$$NHV_{cz} = \frac{\left(Q_{vg} - Q_{NG2} + Q_{NG1}\right) \times NHV_{vg} + \left(Q_{NG2} - Q_{NG1}\right) \times NHV_{NG}}{\left(Q_{vg} + Q_s + Q_{a,premix}\right)}$$

Where:

NHV_{cz} = Net heating value of combustion zone gas, Btu/scf.

NHV_{vg} = Net heating value of flare vent gas for the 15-minute block period, Btu/scf.

Q_{vg} = Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.

Q_{NG2} = Cumulative volumetric flow of supplemental natural gas to the flare during the 15-minute block period, scf.

Q_{NG1} = Cumulative volumetric flow of supplemental natural gas to the flare during the previous 15-minute block period, scf. For the first 15-minute block period of an event, use the volumetric flow value for the current 15-minute block period, *i.e.,* $Q_{NG1}=Q_{NG2}$.

NHV_{NG} = Net heating value of supplemental natural gas to the flare for the 15-minute block period determined according to the requirements in paragraph (j)(5) of this section, Btu/scf.

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

(n) *Calculation methods for determining the net heating value dilution parameter.* The owner or operator shall determine the net heating value dilution parameter (NHV_{dil}) as specified in paragraph (n)(1) or (2) of this section, as applicable.

(1) Except as specified in paragraph (n)(2) of this section, determine the 15-minute block average NHV_{dil} based on the 15-minute block average vent gas and perimeter assist air flow rates using the following equation only during periods when perimeter assist air is used. For 15-minute block periods when there is no cumulative volumetric flow of perimeter assist air, the 15-minute block average NHV_{dil} parameter does not need to be calculated.

$$NHV_{dil} = \frac{Q_{vg} \times Diam \times NHV_{vg}}{\left(Q_{vg} + Q_s + Q_{a,premix} + Q_{a,perimeter}\right)}$$

Where:

NHV_{dil} = Net heating value dilution parameter, Btu/ft^2.

NHV_{vg} = Net heating value of flare vent gas determined for the 15-minute block period, Btu/scf.

Q_{vg} = Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.

Diam = Effective diameter of the unobstructed area of the flare tip for flare vent gas flow, ft. Use the area as determined in paragraph (k)(1) of this section and determine the diameter as

$$Diam = 2 \times \sqrt{Area/\pi}\ .$$

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

$Q_{a,perimeter}$ = Cumulative volumetric flow of perimeter assist air during the 15-minute block period, scf.

(2) Owners or operators of flares that use the feed-forward calculation methodology in paragraph (l)(5)(i) of this section and that monitor gas composition or net heating value in a location representative of the cumulative vent gas stream and that directly monitor supplemental natural gas flow additions to the flare must determine the 15-minute block average NHV_{dil} using the following equation only during periods when perimeter assist air is used. For 15-minute block periods when there is no cumulative

volumetric flow of perimeter assist air, the 15-minute block average NHV_{dil} parameter does not need to be calculated.

$$NHV_{dil} = \frac{\left[\left(Q_{vg} - Q_{NG2} + Q_{NG1} \right) \times NHV_{vg} + \left(Q_{NG2} - Q_{NG1} \right) \times NHV_{NG} \right] \times Diam}{\left(Q_{vg} + Q_{s} + Q_{a,premix} + Q_{a,perimeter} \right)}$$

Where:

NHV_{dil} = Net heating value dilution parameter, Btu/ft^2.

NHV_{vg} = Net heating value of flare vent gas determined for the 15-minute block period, Btu/scf.

Q_{vg} = Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.

Q_{NG2} = Cumulative volumetric flow of supplemental natural gas to the flare during the 15-minute block period, scf.

Q_{NG1} = Cumulative volumetric flow of supplemental natural gas to the flare during the previous 15-minute block period, scf. For the first 15-minute block period of an event, use the volumetric flow value for the current 15-minute block period, *i.e.,* $Q_{NG1} = Q_{NG2}$.

NHV_{NG} = Net heating value of supplemental natural gas to the flare for the 15-minute block period determined according to the requirements in paragraph (j)(5) of this section, Btu/scf.

Diam = Effective diameter of the unobstructed area of the flare tip for flare vent gas flow, ft. Use the area as determined in paragraph (k)(1) of this section and determine the diameter as

$$Diam = 2 \times \sqrt{Area/\pi}\ .$$

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

$Q_{a,perimeter}$ = Cumulative volumetric flow of perimeter assist air during the 15-minute block period, scf.

(o) *Emergency flaring provisions.* The owner or operator of a flare that has the potential to operate above its smokeless capacity under any circumstance shall comply with the provisions in paragraphs (o)(1) through (8) of this section.

(1) Develop a flare management plan to minimize flaring during periods of startup, shutdown, or emergency releases. The flare management plan must include the information described in paragraphs (o)(1)(i) through (vii) of this section.

(i) A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare.

(ii) An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized or prevented during periods of startup, shutdown, or emergency releases. The flare minimization assessment must (at a minimum) consider the items in paragraphs (o)(1)(ii)(A) through (C) of this section. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, each owner or operator of an affected flare shall identify the minimization alternatives that it has implemented by the due date of the flare management plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.

(A) Modification in startup and shutdown procedures to reduce the quantity of process gas discharge to the flare.

(B) Implementation of prevention measures listed for pressure relief devices in § 63.648(j)(5) for each pressure relief valve that can discharge to the flare.

(C) Installation of a flare gas recovery system or, for facilities that are fuel gas rich, a flare gas recovery system and a co-generation unit or combined heat and power unit.

(iii) A description of each affected flare containing the information in paragraphs (o)(1)(iii)(A) through (G) of this section.

(A) A general description of the flare, including whether it is a ground flare or elevated (including height), the type of assist system (*e.g.,* air, steam, pressure, non-assisted), whether the flare is used on a routine basis or if it is only used during periods of startup, shutdown or emergency release, and whether the flare is equipped with a flare gas recovery system.

(B) The smokeless capacity of the flare based on design conditions. Note: A single value must be provided for the smokeless capacity of the flare.

(C) The maximum vent gas flow rate (hydraulic load capacity).

(D) The maximum supplemental gas flow rate.

(E) For flares that receive assist steam, the minimum total steam rate and the maximum total steam rate.

(F) For flares that receive assist air, an indication of whether the fan/blower is single speed, multi-fixed speed (*e.g.,* high, medium, and low speeds), or variable speeds. For fans/blowers with fixed speeds, provide the estimated assist air flow rate at each fixed speed. For variable speeds, provide the design fan curve (*e.g.,* air flow rate as a function of power input).

(G) Simple process flow diagram showing the locations of the flare following components of the flare: Flare tip (date installed, manufacturer, nominal and effective tip diameter, tip drawing); knockout or surge drum(s) or pot(s) (including dimensions and design capacities); flare header(s) and subheader(s); assist system; and ignition system.

(iv) Description and simple process flow diagram showing all gas lines (including flare waste gas, purge or sweep gas (as applicable), supplemental gas) that are associated with the flare. For purge, sweep, supplemental gas, identify the type of gas used. Designate which lines are exempt from composition or net heating value monitoring and why (*e.g.*, natural gas, gas streams that have been demonstrated to have consistent composition, pilot gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor. Designate the pressure relief devices that are vented to the flare.

(v) For each flow rate, gas composition, net heating value or hydrogen concentration monitor identified in paragraph (o)(1)(iv) of this section, provide a detailed description of the manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance and quality assurance procedures.

(vi) For each pressure relief valve vented to the flare identified in paragraph (o)(1)(iv) of this section, provide a detailed description of each pressure release valve, including type of relief device (rupture disc, valve type) diameter of the relief valve, set pressure of the relief valve and listing of the prevention measures implemented. This information may be maintained in an electronic database on-site and does not need to be submitted as part of the flare management plan unless requested to do so by the Administrator.

(vii) Procedures to minimize or eliminate discharges to the flare during the planned startup and shutdown of the refinery process units and ancillary equipment that are connected to the affected flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(2) Each owner or operator required to develop and implement a written flare management plan as described in paragraph (o)(1) of this section must submit the plan to the Administrator as described in paragraphs (o)(2)(i) through (iii) of this section.

(i) The owner or operator must develop and implement the flare management plan no later than January 30, 2019 or at startup for a new flare that commenced construction on or after February 1, 2016.

(ii) The owner or operator must comply with the plan as submitted by the date specified in paragraph (o)(2)(i) of this section. The plan should be updated periodically to account for changes in the operation of the flare, such as new connections to the flare or the installation of a flare gas recovery system, but the plan need be re-submitted to the Administrator only if the owner or operator alters the design smokeless capacity of the flare. The owner or operator must comply with the updated plan as submitted.

(iii) All versions of the plan submitted to the Administrator shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143–01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refineryRTR@epa.gov*.

(3) The owner or operator of a flare subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each flow event that contains regulated material and that meets either the criteria in paragraph (o)(3)(i) or (ii) of this section.

(i) The vent gas flow rate exceeds the smokeless capacity of the flare and visible emissions are present from the flare for more than 5 minutes during any 2 consecutive hours during the release event.

(ii) The vent gas flow rate exceeds the smokeless capacity of the flare and the 15-minute block average flare tip velocity exceeds the maximum flare tip velocity determined using the methods in paragraph (d)(2) of this section.

(4) A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a flare flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (o)(4)(i) through (v) of this section.

(i) You may conduct a single root cause analysis and corrective action analysis for a single continuous flare flow event that meets both of the criteria in paragraphs (o)(3)(i) and (ii) of this section.

(ii) You may conduct a single root cause analysis and corrective action analysis for a single continuous flare flow event regardless of the number of 15-minute block periods in which the flare tip velocity was exceeded or the number of 2 hour periods that contain more the 5 minutes of visible emissions.

(iii) You may conduct a single root cause analysis and corrective action analysis for a single event that causes two or more flares that are operated in series (*i.e.,* cascaded flare systems) to have a flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section.

(iv) You may conduct a single root cause analysis and corrective action analysis for a single event that causes two or more flares to have a flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section, regardless of the configuration of the flares, if the root cause is reasonably expected to be a force majeure event, as defined in this subpart.

(v) Except as provided in paragraphs (o)(4)(iii) and (iv) of this section, if more than one flare has a flow event that meets the criteria in paragraph (o)(3)(i) or (ii) of this section during the same time period, an initial root cause analysis shall be conducted separately for each flare that has a flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section. If the initial root cause analysis indicates that the flow events have the same root cause(s), the initially separate root cause analyses may be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(5) Each owner or operator of a flare required to conduct a root cause analysis and corrective action analysis as specified in paragraphs (o)(3) and (4) of this section shall implement the corrective action(s) identified in the corrective action analysis in accordance with the applicable requirements in paragraphs (o)(5)(i) through (iii) of this section.

(i) All corrective action(s) must be implemented within 45 days of the event for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that no corrective action should be implemented, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the event.

(ii) For corrective actions that cannot be fully implemented within 45 days following the event for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(iii) No later than 45 days following the event for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(6) The owner or operator shall determine the total number of events for which a root cause and corrective action analyses was required during the calendar year for each affected flare separately for events meeting the criteria in paragraph (o)(3)(i) of this section and those meeting the criteria in paragraph (o)(3)(ii) of this section. For the purpose of this requirement, a single root cause analysis conducted for an event that met both of the criteria in paragraphs (o)(3)(i) and (ii) of this section would be counted as an event under each of the separate criteria counts for that flare. Additionally, if a single root cause analysis was conducted for an event that caused multiple flares to meet the criteria in paragraph (o)(3)(i) or (ii) of this section, that event would count as an event for each of the flares for each criteria in paragraph (o)(3) of this section that was met during that event. The owner or operator shall also determine the total number of events for which a root cause and correct action analyses was required and the analyses concluded that the root cause was a force majeure event, as defined in this subpart.

(7) The following events would be a violation of this emergency flaring work practice standard.

(i) Any flow event for which a root cause analysis was required and the root cause was determined to be operator error or poor maintenance.

(ii) Two visible emissions exceedance events meeting the criteria in paragraph (o)(3)(i) of this section that were not caused by a force majeure event from a single flare in a 3 calendar year period for the same root cause for the same equipment.

(iii) Two flare tip velocity exceedance events meeting the criteria in paragraph (o)(3)(ii) of this section that were not caused by a force majeure event from a single flare in a 3 calendar year period for the same root cause for the same equipment.

(iv) Three visible emissions exceedance events meeting the criteria in paragraph (o)(3)(i) of this section that were not caused by a force majeure event from a single flare in a 3 calendar year period for any reason.

(v) Three flare tip velocity exceedance events meeting the criteria in paragraph (o)(3)(ii) of this section that were not caused by a force majeure event from a single flare in a 3 calendar year period for any reason.

(p) *Flare monitoring records.* The owner or operator shall keep the records specified in § 63.655(i)(9).

(q) *Reporting.* The owner or operator shall comply with the reporting requirements specified in § 63.655(g)(11).

(r) *Alternative means of emissions limitation.* An owner or operator may request approval from the Administrator for site-specific operating limits that shall apply specifically to a selected flare. Site-specific operating limits include alternative threshold values for the parameters specified in paragraphs (d) through (f) of this section as well as threshold values for operating parameters other than those specified in paragraphs (d) through (f) of this section. The owner or operator must demonstrate that the flare achieves 96.5 percent combustion efficiency (or 98 percent destruction efficiency) using the site-specific operating limits based on a performance evaluation as described in paragraph (r)(1) of this section. The request shall include information as described in paragraph (r)(2) of this section. The request shall be submitted and followed as described in paragraph (r)(3) of this section.

(1) The owner or operator shall prepare and submit a site-specific test plan and receive approval of the site-specific performance evaluation plan prior to conducting any flare performance evaluation test runs intended for use in developing site-specific operating limits. The site-specific performance evaluation plan shall include, at a minimum, the elements specified in paragraphs (r)(1)(i) through (ix) of this section. Upon approval of the site-specific performance evaluation plan, the owner or operator shall conduct performance evaluation test runs for the flare following the procedures described in the site-specific performance evaluation plan.

(i) The design and dimensions of the flare, flare type (air-assisted only, steam-assisted only, air- and steam-assisted, pressure-assisted, or non-assisted), and description of gas being flared, including quantity of gas flared, frequency of flaring events (if periodic), expected net heating value of flare vent gas, minimum total steam assist rate.

(ii) The operating conditions (vent gas compositions, vent gas flow rates and assist flow rates, if applicable) likely to be encountered by the flare during normal operations and the operating conditions for the test period.

(iii) A description of (including sample calculations illustrating) the planned data reduction and calculations to determine the flare combustion or destruction efficiency.

(iv) Site-specific operating parameters to be monitored continuously during the flare performance evaluation. These parameters may include but are not limited to vent gas flow rate, steam and/or air assist flow rates, and flare vent gas composition. If new operating parameters are proposed for use other than those specified in paragraphs (d) through (f) of this section, an explanation of the relevance of the proposed operating parameter(s) as an indicator of flare combustion performance and why the alternative operating parameter(s) can adequately ensure that the flare achieves the required combustion efficiency.

(v) A detailed description of the measurement methods, monitored pollutant(s), measurement locations, measurement frequency, and recording frequency proposed for both emission measurements and flare operating parameters.

(vi) A description of (including sample calculations illustrating) the planned data reduction and calculations to determine the flare operating parameters.

(vii) The minimum number and length of test runs and range of operating values to be evaluated during the performance evaluation. A sufficient number of test runs shall be conducted to identify the point at which the combustion/destruction efficiency of the flare deteriorates.

(viii) [Reserved]

(ix) Test schedule.

(2) The request for flare-specific operating limits shall include sufficient and appropriate data, as determined by the Administrator, to allow the Administrator to confirm that the selected site-specific operating limit(s) adequately ensures that the flare destruction efficiency is 98 percent or greater or that the flare combustion efficiency is 96.5 percent or greater at all times. At a minimum, the request shall contain the information described in paragraphs (r)(2)(i) through (iv) of this section.

(i) The design and dimensions of the flare, flare type (air-assisted only, steam-assisted only, air- and steam-assisted, pressure-assisted, or non-assisted), and description of gas being flared, including quantity of gas flared, frequency of flaring events (if periodic), expected net heating value of flare vent gas, minimum total steam assist rate.

(ii) Results of each performance evaluation test run conducted, including, at a minimum:

(A) The measured combustion/destruction efficiency.

(B) The measured or calculated operating parameters for each test run. If operating parameters are calculated, the raw data from which the parameters are calculated must be included in the test report.

(C) Measurement location descriptions for both emission measurements and flare operating parameters.

(D) Description of sampling and analysis procedures (including number and length of test runs) and any modifications to standard procedures. If there were deviations from the approved test plan, a detailed description of the deviations and rationale why the test results or calculation procedures used are appropriate.

(E) Operating conditions (*e.g.*, vent gas composition, assist rates, etc.) that occurred during the test.

(F) Quality assurance procedures.

(G) Records of calibrations.

(H) Raw data sheets for field sampling.

(I) Raw data sheets for field and laboratory analyses.

(J) Documentation of calculations.

(iii) The selected flare-specific operating limit values based on the performance evaluation test results, including the averaging time for the operating limit(s), and rationale why the selected values and averaging times are sufficiently stringent to ensure proper flare performance. If new operating parameters or averaging times are proposed for use other than those specified in paragraphs (d) through (f) of this section, an explanation of why the alternative operating parameter(s) or averaging time(s) adequately ensures the flare achieves the required combustion efficiency.

(iv) The means by which the owner or operator will document on-going, continuous compliance with the selected flare-specific operating limit(s), including the specific measurement location and frequencies, calculation procedures, and records to be maintained.

(3) The request shall be submitted as described in paragraphs (r)(3)(i) through (iv) of this section.

(i) The owner or operator may request approval from the Administrator at any time upon completion of a performance evaluation conducted following the methods in an approved site-specific performance evaluation plan for an operating limit(s) that shall apply specifically to that flare.

(ii) The request must be submitted to the Administrator for approval. The owner or operator must continue to comply with the applicable standards for flares in this subpart until the requirements in § 63.6(g)(1) are met and a notice is published in the **Federal Register** allowing use of such an alternative means of emission limitation.

(iii) The request shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143–01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refineryrtr@epa.gov.*

(iv) If the Administrator finds any deficiencies in the request, the request must be revised to address the deficiencies and be re-submitted for approval within 45 days of receipt of the notice of deficiencies. The owner or operator must comply with the revised request as submitted until it is approved.

(4) The approval process for a request for a flare-specific operating limit(s) is described in paragraphs (r)(4)(i) through (iii) of this section.

(i) Approval by the Administrator of a flare-specific operating limit(s) request will be based on the completeness, accuracy and reasonableness of the request. Factors that the EPA will consider in reviewing the request for approval include, but are not limited to, those described in paragraphs (r)(4)(i)(A) through (C) of this section.

(A) The description of the flare design and operating characteristics.

(B) If a new operating parameter(s) other than those specified in paragraphs (d) through (f) of this section is proposed, the explanation of how the proposed operating parameter(s) serves a good indicator(s) of flare combustion performance.

(C) The results of the flare performance evaluation test runs and the establishment of operating limits that ensures that the flare destruction efficiency is 98 percent or greater or that the flare combustion efficiency is 96.5 percent or greater at all times.

(D) The completeness of the flare performance evaluation test report.

(ii) If the request is approved by the Administrator, a flare-specific operating limit(s) will be established at the level(s) demonstrated in the approved request.

(iii) If the Administrator finds any deficiencies in the request, the request must be revised to address the deficiencies and be re-submitted for approval.

■ 33. Section 63.671 is added to read as follows:

§ 63.671 Requirements for flare monitoring systems.

(a) *Operation of CPMS.* For each CPMS installed to comply with applicable provisions in § 63.670, the owner or operator shall install, operate, calibrate, and maintain the CPMS as specified in paragraphs (a)(1) through (8) of this section.

(1) Except for CPMS installed for pilot flame monitoring, all monitoring equipment must meet the applicable minimum accuracy, calibration and quality control requirements specified in table 13 of this subpart.

(2) The owner or operator shall ensure the readout (that portion of the CPMS that provides a visual display or record) or other indication of the monitored operating parameter from any CPMS required for compliance is readily accessible onsite for operational control or inspection by the operator of the source.

(3) All CPMS must complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period.

(4) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall operate all CPMS and collect data continuously at all times when regulated emissions are routed to the flare.

(5) The owner or operator shall operate, maintain, and calibrate each CPMS according to the CPMS monitoring plan specified in paragraph (b) of this section.

(6) For each CPMS except for CPMS installed for pilot flame monitoring, the owner or operator shall comply with the out-of-control procedures described in paragraph (c) of this section.

(7) The owner or operator shall reduce data from a CPMS as specified in paragraph (d) of this section.

(8) The CPMS must be capable of measuring the appropriate parameter over the range of values expected for that measurement location. The data recording system associated with each CPMS must have a resolution that is equal to or better than the required system accuracy.

(b) *CPMS monitoring plan.* The owner or operator shall develop and implement a CPMS quality control program documented in a CPMS monitoring plan that covers each flare subject to the provisions in § 63.670 and each CPMS installed to comply with applicable provisions in § 63.670. The owner or operator shall have the CPMS monitoring plan readily available on-site at all times and shall submit a copy of the CPMS monitoring plan to the Administrator upon request by the Administrator. The CPMS monitoring plan must contain the information listed in paragraphs (b)(1) through (5) of this section.

(1) Identification of the specific flare being monitored and the flare type (air-assisted only, steam-assisted only, air- and steam-assisted, pressure-assisted, or non-assisted).

(2) Identification of the parameter to be monitored by the CPMS and the expected parameter range, including worst case and normal operation.

(3) Description of the monitoring equipment, including the information specified in paragraphs (b)(3)(i) through (vii) of this section.

(i) Manufacturer and model number for all monitoring equipment components installed to comply with applicable provisions in § 63.670.

(ii) Performance specifications, as provided by the manufacturer, and any differences expected for this installation and operation.

(iii) The location of the CPMS sampling probe or other interface and a justification of how the location meets the requirements of paragraph (a)(1) of this section.

(iv) Placement of the CPMS readout, or other indication of parameter values, indicating how the location meets the requirements of paragraph (a)(2) of this section.

(v) Span of the CPMS. The span of the CPMS sensor and analyzer must encompass the full range of all expected values.

(vi) How data outside of the span of the CPMS will be handled and the corrective action that will be taken to reduce and eliminate such occurrences in the future.

(vii) Identification of the parameter detected by the parametric signal analyzer and the algorithm used to convert these values into the operating parameter monitored to demonstrate compliance, if the parameter detected is different from the operating parameter monitored.

(4) Description of the data collection and reduction systems, including the information specified in paragraphs (b)(4)(i) through (iii) of this section.

(i) A copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard and to calculate the applicable averages.

(ii) Identification of whether the algorithm excludes data collected during CPMS breakdowns, out-of-control periods, repairs, maintenance periods, instrument adjustments or checks to maintain precision and accuracy, calibration checks, and zero (low-level), mid-level (if applicable) and high-level adjustments.

(iii) If the data acquisition algorithm does not exclude data collected during CPMS breakdowns, out-of-control periods, repairs, maintenance periods, instrument adjustments or checks to maintain precision and accuracy, calibration checks, and zero (low-level), mid-level (if applicable) and high-level adjustments, a description of the procedure for excluding this data when the averages calculated as specified in paragraph (e) of this section are determined.

(5) Routine quality control and assurance procedures, including descriptions of the procedures listed in paragraphs (b)(5)(i) through (vi) of this section and a schedule for conducting these procedures. The routine procedures must provide an assessment of CPMS performance.

(i) Initial and subsequent calibration of the CPMS and acceptance criteria.

(ii) Determination and adjustment of the calibration drift of the CPMS.

(iii) Daily checks for indications that the system is responding. If the CPMS system includes an internal system check, the owner or operator may use the results to verify the system is responding, as long as the system provides an alarm to the owner or operator or the owner or operator checks the internal system results daily for proper operation and the results are recorded.

(iv) Preventive maintenance of the CPMS, including spare parts inventory.

(v) Data recording, calculations and reporting.

(vi) Program of corrective action for a CPMS that is not operating properly.

(c) *Out-of-control periods.* For each CPMS installed to comply with applicable provisions in § 63.670 except for CPMS installed for pilot flame monitoring, the owner or operator shall comply with the out-of-control procedures described in paragraphs (c)(1) and (2) of this section.

(1) A CPMS is out-of-control if the zero (low-level), mid-level (if applicable) or high-level calibration drift exceeds two times the accuracy requirement of table 13 of this subpart.

(2) When the CPMS is out of control, the owner or operator shall take the necessary corrective action and repeat all necessary tests that indicate the system is out of control. The owner or operator shall take corrective action and conduct retesting until the performance requirements are below the applicable limits. The beginning of the out-of-control period is the hour a performance check (*e.g.*, calibration drift) that indicates an exceedance of the performance requirements established in this section is conducted. The end of the out-of-control period is the hour following the completion of corrective action and successful demonstration that the system is within the allowable limits. The owner or operator shall not use data recorded during periods the CPMS is out of control in data averages and calculations, used to report emissions or operating levels, as specified in paragraph (d)(3) of this section.

(d) *CPMS data reduction.* The owner or operator shall reduce data from a CPMS installed to comply with applicable provisions in § 63.670 as specified in paragraphs (d)(1) through (3) of this section.

(1) The owner or operator may round the data to the same number of significant digits used in that operating limit.

(2) Periods of non-operation of the process unit (or portion thereof) resulting in cessation of the emissions to which the monitoring applies must not be included in the 15-minute block averages.

(3) Periods when the CPMS is out of control must not be included in the 15-minute block averages.

(e) *Additional requirements for gas chromatographs.* For monitors used to determine compositional analysis for net heating value per § 63.670(j)(1), the gas chromatograph must also meet the requirements of paragraphs (e)(1) through (3) of this section.

(1) The quality assurance requirements are in table 13 of this subpart.

(2) The calibration gases must meet one of the following options:

(i) The owner or operator must use a calibration gas or multiple gases that include all of compounds listed in paragraphs (e)(2)(i)(A) through (K) of this section that may be reasonably expected to exist in the flare gas stream and optionally include any of the compounds listed in paragraphs (e)(2)(i)(L) through (O) of this section. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, the owner or operator must calibrate the instrument on all of the gases.

(A) Hydrogen.

(B) Methane.

(C) Ethane.

(D) Ethylene.

(E) Propane.

(F) Propylene.

(G) n-Butane.

(H) iso-Butane.

(I) Butene (general). It is not necessary to separately speciate butene isomers, but the net heating value of trans-butene must be used for co-eluting butene isomers.

(J) 1,3-Butadiene. It is not necessary to separately speciate butadiene isomers, but you must use the response factor and net heating value of 1,3-butadiene for co-eluting butadiene isomers.

(K) n-Pentane. Use the response factor for n-pentane to quantify all C5+ hydrocarbons.

(L) Acetylene (optional).

(M) Carbon monoxide (optional).

(N) Propadiene (optional).

(O) Hydrogen sulfide (optional).

(ii) The owner or operator must 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, the owner or operator must calibrate the instrument on all of the gases.

(3) If the owner or operator chooses to use a surrogate calibration gas under paragraph (e)(2)(ii) of this section, the owner or operator must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) 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.

(ii) Use the response factor for n-pentane to quantify unknown components detected in the analysis that elute after n-pentane.

■ 34. The appendix to subpart CC is amended in table 6 by:

■ a. Revising the entries ''63.5(d)(1)(ii)'' and ''63.5(f)'';

■ b. Removing the entry ''63.6(e)(1)'';

■ c. Adding, in numerical order, the entries ''63.6(e)(1)(i) and (ii)'' and ''63.6(e)(1)(iii)'';

■ d. Revising the entries ''63.6(e)(3)(i),'' ''63.6(e)(3)(iii)–63.6(e)(3)(ix),'' and ''63.6(f)(1)'';

■ e. Removing the entry ''63.6(f)(2) and (3)'';

■ f. Adding, in numerical order, the entries ''63.6(f)(2)'' and ''63.6(f)(3)'';

■ g. Removing the entry ''63.6(h)(1) and 63.6(h)(2)'';

■ h. Adding, in numerical order, the entries ''63.6(h)(1)'' and ''63.6(h)(2)'';

■ i. Revising the entries ''63.7(b)'' and ''63.7(e)(1)'';

■ j. Removing the entry ''63.8(a)'';

■ k. Adding, in numerical order, the entries ''63.8(a)(1) and (2),'' ''63.8(a)(3),'' and ''63.8(a)(4)'';

■ l. Revising the entry ''63.8(c)(1)'';

■ m. Adding, in numerical order, the entries ''63.8(c)(1)(i)'' and ''63.8(c)(1)(iii)'';

■ n. Revising the entries ''63.8(c)(4),'' ''63.8(c)(5)–63.8(c)(8),'' ''63.8(d),'' ''63.8(e),'' ''63.8(g),'' ''63.10(b)(2)(i),'' ''63.10(b)(2)(ii),'' ''63.10(b)(2)(iv),'' ''63.10(b)(2)(v),'' and ''63.10(b)(2)(vii)'';

■ o. Removing the entry ''63.10(c)(9)–63.10(c)(15)'';

■ p. Adding, in numerical order, the entries ''63.10(c)(9),'' ''63.10(c)(10)–63.10(c)(11),'' and ''63.10(c)(12)–63.10(c)(15)'';

■ q. Revising the entry ''63.10(d)(2)'';

■ r. Removing the entries ''63.10(d)(5)(i)'' and ''63.10(d)(5)(ii)'';

■ s. Adding, in numerical order, the entry ''63.10(d)(5)'';

■ t. Removing the entry ''63.11–63.16'';

■ u. Adding, in numerical order, the entries ''63.11'' and ''63.12–63.16'';

■ v. Revising footnote a.

■ w. Removing footnote b.

The revisions and additions read as follows:

Appendix to Subpart CC of Part 63—Tables

* * * * *

Table 6—General Provisions Applicability to Subpart CC[a]

Reference	Applies to subpart CC	Comment
* *	*	* * * *
63.5(d)(1)(ii)	Yes	Except that for affected sources subject to this subpart, emission estimates specified in § 63.5(d)(1)(ii)(H) are not required, and § 63.5(d)(1)(ii)(G) and (I) are Reserved and do not apply.
* *	*	* * * *
63.5(f)	Yes	Except that the cross-reference in § 63.5(f)(2) to § 63.9(b)(2) does not apply.
* *	*	* * * *
63.6(e)(1)(i) and (ii)	No	See § 63.642(n) for general duty requirement.
63.6(e)(1)(iii)	Yes.	
* *	*	* * * *
63.6(e)(3)(i)	No.	
* *	*	* * * *
63.6(e)(3)(iii)–63.6(e)(3)(ix)	No.	
63.6(f)(1)	No.	
63.6(f)(2)	Yes	Except the phrase ''as specified in § 63.7(c)'' in § 63.6(f)(2)(iii)(D) does not apply because this subpart does not require a site-specific test plan.
63.6(f)(3)	Yes	Except the cross-references to § 63.6(f)(1) and (e)(1)(i) are changed to § 63.642(n).
* *	*	* * * *
63.6(h)(1)	No.	
63.6(h)(2)	Yes	Except § 63.6(h)(2)(ii), which is reserved.
* *	*	* * * *
63.7(b)	Yes	Except this subpart requires notification of performance test at least 30 days (rather than 60 days) prior to the performance test.
* *	*	* * * *
63.7(e)(1)	No	See § 63.642(d)(3).
* *	*	* * * *
63.8(a)(1) and (2)	Yes.	
63.8(a)(3)	No	Reserved.
63.8(a)(4)	Yes	Except that for a flare complying with § 63.670, the cross-reference to § 63.11 in this paragraph does not include § 63.11(b).
* *	*	* * * *
63.8(c)(1)	Yes	Except § 63.8(c)(1)(i) and (iii).
63.8(c)(1)(i)	No	See § 63.642(n).
63.8(c)(1)(iii)	No.	

TABLE 6—GENERAL PROVISIONS APPLICABILITY TO SUBPART CC[a]—Continued

Reference	Applies to subpart CC	Comment
* *	*	* * * *
63.8(c)(4)	Yes	Except that for sources other than flares, this subpart specifies the monitoring cycle frequency specified in § 63.8(c)(4)(ii) is ''once every hour'' rather than ''for each successive 15-minute period.''
63.8(c)(5)–63.8(c)(8)	No	This subpart specifies continuous monitoring system requirements.
63.8(d)	No	This subpart specifies quality control procedures for continuous monitoring systems.
63.8(e)	Yes.	
* *	*	* * * *
63.8(g)	No	This subpart specifies data reduction procedures in §§ 63.655(i)(3) and 63.671(d).
* *	*	* * * *
63.10(b)(2)(i)	No.	
63.10(b)(2)(ii)	No	§ 63.655(i) specifies the records that must be kept.
* *	*	* * * *
63.10(b)(2)(iv)	No.	
63.10(b)(2)(v)	No.	
* *	*	* * * *
63.10(b)(2)(vii)	No	§ 63.655(i) specifies records to be kept for parameters measured with continuous monitors.
* *	*	* * * *
63.10(c)(9)	No	Reserved.
63.10(c)(10)–63.10(c)(11)	No	§ 63.655(i) specifies the records that must be kept.
63.10(c)(12)–63.10(c)(15)	No.	
* *	*	* * * *
63.10(d)(2)	No	Although § 63.655(f) specifies performance test reporting, EPA may approve other timeframes for submittal of performance test data.
* *	*	* * * *
63.10(d)(5)	No	§ 63.655(g) specifies the reporting requirements.
* *	*	* * * *
63.11	Yes	Except that flares complying with § 63.670 are not subject to the requirements of § 63.11(b).
63.12–63.16	Yes.	

[a] Wherever subpart A of this part specifies ''postmark'' dates, submittals may be sent by methods other than the U.S. Mail (*e.g.,* by fax or courier). Submittals shall be sent by the specified dates, but a postmark is not required.

■ 35. The appendix to subpart CC is amended in table 10 by:

■ a. Redesignating the entry ''Flare'' as ''Flare (if meeting the requirements of §§ 63.643 and 63.644)'';

■ b. Adding the entry ''Flare (if meeting the requirements of §§ 63.670 and 63.671)'' after newly redesignated entry ''Flare (if meeting the requirements of §§ 63.643 and 63.644)'';

■ c. Revising the entry ''All control devices''; and

■ d. Revising footnote i.

The revisions and additions read as follows:

Appendix to Subpart CC of Part 63—Tables

* * * * *

TABLE 10—MISCELLANEOUS PROCESS VENTS—MONITORING, RECORDKEEPING AND REPORTING REQUIREMENTS FOR COMPLYING WITH 98 WEIGHT-PERCENT REDUCTION OF TOTAL ORGANIC HAP EMISSIONS OR A LIMIT OF 20 PARTS PER MILLION BY VOLUME

Control device	Parameters to be monitored[a]	Recordkeeping and reporting requirements for monitored parameters
* *	* *	* * *
Flare (if meeting the requirements of §§ 63.670 and 63.671).	The parameters specified in § 63.670.	1. Records as specified in § 63.655(i)(9). 2. Report information as specified in § 63.655(g)(11)—PR.[g]
All control devices	Presence of flow diverted to the atmosphere from the control device (§ 63.644(c)(1)) *or*	1. Hourly records of whether the flow indicator was operating and whether flow was detected at any time during each hour. Record and report the times and durations of all periods when the vent stream is diverted through a bypass line or the monitor is not operating—PR.[g]

TABLE 10—MISCELLANEOUS PROCESS VENTS—MONITORING, RECORDKEEPING AND REPORTING REQUIREMENTS FOR COMPLYING WITH 98 WEIGHT-PERCENT REDUCTION OF TOTAL ORGANIC HAP EMISSIONS OR A LIMIT OF 20 PARTS PER MILLION BY VOLUME—Continued

Control device	Parameters to be monitored[a]	Recordkeeping and reporting requirements for monitored parameters
	Monthly inspections of sealed valves (§ 63.644(c)(2)).	1. Records that monthly inspections were performed. 2. Record and report all monthly inspections that show the valves are not closed or the seal has been changed—PR.[g]

[a] Regulatory citations are listed in parentheses.

* * * * * * *

[g] PR = Periodic Reports described in § 63.655(g).

* * * * * * *

[i] Process vents that are routed to refinery fuel gas systems are not regulated under this subpart provided that on and after January 30, 2019, any flares receiving gas from that fuel gas system are in compliance with § 63.670. No monitoring, recordkeeping, or reporting is required for boilers and process heaters that combust refinery fuel gas.

■ 36. The appendix to subpart CC is amended by adding table 11 to read as follows:

Appendix to Subpart CC of Part 63—Tables

* * * * *

TABLE 11—COMPLIANCE DATES AND REQUIREMENTS

If the construction/reconstruction date[a] is . . .	Then the owner or operator must comply with . . .	And the owner or operator must achieve compliance . . .	Except as provided in . . .
(1) After June 30, 2014	(i) Requirements for new sources in §§ 63.640 through 63.642, 63.647, 63.650 through 63.653, and 63.656 through 63.660.	Upon initial startup or February 1, 2016, whichever is later.	§ 63.640(k), (l) and (m).
	(ii) The new source requirements in § 63.654 for heat exchange systems.	Upon initial startup or October 28, 2009, whichever is later.	§ 63.640(k), (l) and (m).
(2) After September 4, 2007 but on or before June 30, 2014.	(i) Requirements for new sources in §§ 63.640 through 63.653 and 63.656[b c].	Upon initial startup	§ 63.640(k), (l) and (m).
	(ii) Requirements for new sources in §§ 63.640 through 63.645, §§ 63.647 through 63.653, and §§ 63.656 and 63.657[b].	On or before January 30, 2019	§ 63.640(k), (l) and (m).
	(iii) Requirements for existing sources in § 63.658.	On or before January 30, 2018	§ 63.640(k), (l) and (m).
	(iv) Requirements for new sources in § 63.660[c].	On or before April 29, 2016	§ 63.640(k), (l) and (m).
	(v) The new source requirements in § 63.654 for heat exchange systems.	Upon initial startup or October 28, 2009, whichever is later.	§ 63.640(k), (l) and (m).
(3) After July 14, 1994 but on or before September 4, 2007.	(i) Requirements for new sources in §§ 63.640 through 63.653 and 63.656[d e].	Upon initial startup or August 18, 1995, whichever is later.	§ 63.640(k), (l) and (m).
	(ii) Requirements for new sources in §§ 63.640 through 63.645, 63.647 through 63.653, and 63.656 and 63.657[d].	On or before January 30, 2019	§ 63.640(k), (l) and (m).
	(iii) Requirements for existing sources in § 63.658.	On or before January 30, 2018	§ 63.640(k), (l) and (m).
	(iv) Requirements for new sources in § 63.660[e].	On or before April 29, 2016	§ 63.640(k), (l) and (m).
	(v) The existing source requirements in § 63.654 for heat exchange systems.	On or before October 29, 2012	§ 63.640(k), (l) and (m).
(4) On or before July 14, 1994	(i) Requirements for existing sources in §§ 63.640 through 63.653 and 63.656[f g].	(a) On or before August 18, 1998	(1) § 63.640(k), (l) and (m). (2) § 63.6(c)(5) of subpart A of this part or unless an extension has been granted by the Administrator as provided in § 63.6(i) of subpart A of this part.
	(ii) Requirements for existing sources in §§ 63.640 through 63.645, 63.647 through 63.653, and 63.656 and 63.657[f].	On or before January 30, 2019	§ 63.640(k), (l) and (m).

TABLE 11—COMPLIANCE DATES AND REQUIREMENTS—Continued

If the construction/reconstruction date [a] is . . .	Then the owner or operator must comply with . . .	And the owner or operator must achieve compliance . . .	Except as provided in . . .
	(iii) Requirements for existing sources in § 63.658.	On or before January 30, 2018	§ 63.640(k), (l) and (m).
	(iv) Requirements for existing sources in § 63.660 [g].	On or before April 29, 2016	§ 63.640(k), (l) and (m).
(v) The existing source requirements in § 63.654 for heat exchange systems	On or before October 29, 2012	§ 63.640(k), (l) and (m).	

[a] For purposes of this table, the construction/reconstruction date means the date of construction or reconstruction of an entire affected source or the date of a process unit addition or change meeting the criteria in § 63.640(i) or (j). If a process unit addition or change does not meet the criteria in § 63.640(i) or (j), the process unit shall comply with the applicable requirements for existing sources.

[b] Between the compliance dates in items (2)(i) and (2)(ii) of this table, the owner or operator may elect to comply with either the requirements in item (2)(i) or item (2)(ii) of this table. The requirements in item (2)(i) of this table no longer apply after demonstrated compliance with the requirements in item (2)(ii) of this table.

[c] Between the compliance dates in items (2)(i) and (2)(iv) of this table, the owner or operator may elect to comply with either the requirements in item (2)(i) or item (2)(iv) of this table. The requirements in item (2)(i) of this table no longer apply after demonstrated compliance with the requirements in item (2)(iv) of this table.

[d] Between the compliance dates in items (3)(i) and (3)(ii) of this table, the owner or operator may elect to comply with either the requirements in item (3)(i) or item (3)(ii) of this table. The requirements in item (3)(i) of this table no longer apply after demonstrated compliance with the requirements in item (3)(ii) of this table.

[e] Between the compliance dates in items (3)(i) and (3)(iv) of this table, the owner or operator may elect to comply with either the requirements in item (3)(i) or item (3)(iv) of this table. The requirements in item (3)(i) of this table no longer apply after demonstrated compliance with the requirements in item (3)(iv) of this table.

[f] Between the compliance dates in items (4)(i) and (4)(ii) of this table, the owner or operator may elect to comply with either the requirements in item (4)(i) or item (4)(ii) of this table. The requirements in item (4)(i) of this table no longer apply after demonstrated compliance with the requirements in item (4)(ii) of this table.

[g] Between the compliance dates in items (4)(i) and (4)(iv) of this table, the owner or operator may elect to comply with either the requirements in item (4)(i) or item (4)(iv) of this table. The requirements in item (4)(i) of this table no longer apply after demonstrated compliance with the requirements in item (4)(iv) of this table.

■ 37. The appendix to subpart CC is amended by adding table 12 to read as follows:

Appendix to Subpart CC of Part 63—Tables

* * * * *

TABLE 12—INDIVIDUAL COMPONENT PROPERTIES

Component	Molecular formula	MW_i (pounds per pound-mole)	CMN_i (mole per mole)	NHV_i (British thermal units per standard cubic foot)	LFL_i (volume %)
Acetylene	C_2H_2	26.04	2	1,404	2.5
Benzene	C_6H_6	78.11	6	3,591	1.3
1,2-Butadiene	C_4H_6	54.09	4	2,794	2.0
1,3-Butadiene	C_4H_6	54.09	4	2,690	2.0
iso-Butane	C_4H_{10}	58.12	4	2,957	1.8
n-Butane	C_4H_{10}	58.12	4	2,968	1.8
cis-Butene	C_4H_8	56.11	4	2,830	1.6
iso-Butene	C_4H_8	56.11	4	2,928	1.8
trans-Butene	C_4H_8	56.11	4	2,826	1.7
Carbon Dioxide	CO_2	44.01	1	0	∞
Carbon Monoxide	CO	28.01	1	316	12.5
Cyclopropane	C_3H_6	42.08	3	2,185	2.4
Ethane	C_2H_6	30.07	2	1,595	3.0
Ethylene	C_2H_4	28.05	2	1,477	2.7
Hydrogen	H_2	2.02	0	1,212[a]	4.0
Hydrogen Sulfide	H_2S	34.08	0	587	4.0
Methane	CH_4	16.04	1	896	5.0
Methyl-Acetylene	C_3H_4	40.06	3	2,088	1.7
Nitrogen	N_2	28.01	0	0	∞
Oxygen	O_2	32.00	0	0	∞
Pentane+ (C5+)	C_5H_{12}	72.15	5	3,655	1.4
Propadiene	C_3H_4	40.06	3	2,066	2.16
Propane	C_3H_8	44.10	3	2,281	2.1
Propylene	C_3H_6	42.08	3	2,150	2.4
Water	H_2O	18.02	0	0	∞

[a] The theoretical net heating value for hydrogen is 274 Btu/scf, but for the purposes of the flare requirement in this subpart, a net heating value of 1,212 Btu/scf shall be used.

■ 38. The appendix to subpart CC is amended by adding table 13 to read as follows:

Appendix to Subpart CC of Part 63—Tables

* * * * *

TABLE 13—CALIBRATION AND QUALITY CONTROL REQUIREMENTS FOR CPMS

Parameter	Minimum accuracy requirements	Calibration requirements
Temperature	±1 percent over the normal range of temperature measured, expressed in degrees Celsius (C), or 2.8 degrees C, whichever is greater.	Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the temperature exceeded the manufacturer's specified maximum rated temperature or install a new temperature sensor. At least quarterly, inspect all components for integrity and all electrical connections for continuity, oxidation, and galvanic corrosion, unless the CPMS has a redundant temperature sensor. Record the results of each calibration check and inspection. Locate the temperature sensor in a position that provides a representative temperature; shield the temperature sensor system from electromagnetic interference and chemical contaminants.
Flow Rate for All Flows Other Than Flare Vent Gas.	±5 percent over the normal range of flow measured or 1.9 liters per minute (0.5 gallons per minute), whichever is greater, for liquid flow. ±5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute), whichever is greater, for gas flow. ±5 percent over the normal range measured for mass flow.	Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor. At least quarterly, inspect all components for leakage, unless the CPMS has a redundant flow sensor. Record the results of each calibration check and inspection. Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.
Flare Vent Gas Flow Rate	±20 percent of flow rate at velocities ranging from 0.03 to 0.3 meters per second (0.1 to 1 feet per second). ±5 percent of flow rate at velocities greater than 0.3 meters per second (1 feet per second).	Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor. At least quarterly, inspect all components for leakage, unless the CPMS has a redundant flow sensor. Record the results of each calibration check and inspection. Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.
Pressure	±5 percent over the normal operating range or 0.12 kilopascals (0.5 inches of water column), whichever is greater.	Review pressure sensor readings at least once a week for straightline (unchanging) pressure and perform corrective action to ensure proper pressure sensor operation if blockage is indicated. Using an instrument recommended by the sensor's manufacturer, check gauge calibration and transducer calibration annually; conduct calibration checks following any period of more than 24 hours throughout which the pressure exceeded the manufacturer's specified maximum rated pressure or install a new pressure sensor. At least quarterly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage, unless the CPMS has a redundant pressure sensor. Record the results of each calibration check and inspection. Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.
Net Heating Value by Calorimeter	±2 percent of span	Specify calibration requirements in your site specific CPMS monitoring plan. Calibration requirements should follow manufacturer's recommendations at a minimum. Temperature control (heated and/or cooled as necessary) the sampling system to ensure proper year-round operation. Where feasible, select a sampling location at least two equivalent diameters downstream from and 0.5 equivalent diameters upstream from the nearest disturbance. Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration or emission rate occurs.

TABLE 13—CALIBRATION AND QUALITY CONTROL REQUIREMENTS FOR CPMS—Continued

Parameter	Minimum accuracy requirements	Calibration requirements
Net Heating Value by Gas Chromatograph.	As specified in Performance Specification 9 of 40 CFR part 60, appendix B	Follow the procedure in Performance Specification 9 of 40 CFR part 60, appendix B, 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).
Hydrogen analyzer	±2 percent over the concentration measured or 0.1 volume percent, whichever is greater.	Specify calibration requirements in your site specific CPMS monitoring plan. Calibration requirements should follow manufacturer's recommendations at a minimum. Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration occurs.

Subpart UUU—National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

■ 39. Section 63.1562 is amended by revising paragraphs (b)(3) and (f)(5) to read as follows:

§ 63.1562 What parts of my plant are covered by this subpart?

* * * * *

(b) * * *

(3) The process vent or group of process vents on Claus or other types of sulfur recovery plant units or the tail gas treatment units serving sulfur recovery plants that are associated with sulfur recovery.

* * * * *

(f) * * *

(5) Gaseous streams routed to a fuel gas system, provided that on and after January 30, 2019, any flares receiving gas from the fuel gas system are subject to § 63.670.

■ 40. Section 63.1564 is amended by:

■ a. Revising paragraphs (a)(1) and (2);

■ b. Adding paragraph (a)(5);

■ c. Removing the equation following paragraph (b)(4)(ii) and adding it after paragraph (b)(4)(iii) introductory text;

■ d. Revising paragraphs (b)(2), (b)(4)(i) and (ii), and (b)(4)(iv); and

■ e. Adding paragraph (c)(5).

The revisions and additions read as follows:

§ 63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?

(a) * * *

(1) Except as provided in paragraph (a)(5) of this section, meet each emission limitation in Table 1 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for PM in § 60.102 of this chapter or is subject to § 60.102a(b)(1) of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit is not subject to the NSPS for PM, you can choose from the four options in paragraphs (a)(1)(i) through (vi) of this section:

(i) You can elect to comply with the NSPS for PM in § 60.102 of this chapter (Option 1a);

(ii) You can elect to comply with the NSPS for PM coke burn-off emission limit in § 60.102a(b)(1) of this chapter (Option 1b);

(iii) You can elect to comply with the NSPS for PM concentration limit in § 60.102a(b)(1) of this chapter (Option 1c);

(iv) You can elect to comply with the PM per coke burn-off emission limit in § 60.102a(b)(1) of this chapter (Option 2);

(v) You can elect to comply with the Nickel (Ni) lb/hr emission limit (Option 3); or

(vi) You can elect to comply with the Ni per coke burn-off emission limit (Option 4).

(2) Comply with each operating limit in Table 2 of this subpart that applies to you. When a specific control device may be monitored using more than one continuous parameter monitoring system, you may select the parameter with which you will comply. You must provide notice to the Administrator (or other designated authority) if you elect to change the monitoring option.

* * * * *

(5) During periods of startup, shutdown and hot standby, you can choose from the two options in paragraphs (a)(5)(i) and (ii) of this section:

(i) You can elect to comply with the requirements in paragraphs (a)(1) and (2) of this section, except catalytic cracking units controlled using a wet scrubber must maintain only the liquid to gas ratio operating limit (the pressure drop operating limit does not apply); or

(ii) You can elect to maintain the inlet velocity to the primary internal cyclones of the catalytic cracking unit catalyst regenerator at or above 20 feet per second.

(b) * * *

(2) Conduct a performance test for each catalytic cracking unit according to the requirements in § 63.1571 and under the conditions specified in Table 4 of this subpart.

* * * * *

(4) * * *

(i) If you elect Option 1b or Option 2 in paragraph (a)(1)(ii) or (iv) of this section, compute the PM emission rate (lb/1,000 lb of coke burn-off) for each run using Equations 1, 2, and 3 (if applicable) of this section and the site-specific opacity limit, if applicable, using Equation 4 of this section as follows:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \left[\left(\frac{\%CO}{2} \right) + \%CO_2 + \%O_2 \right] + K_3 Q_{oxy} (\%O_{xy}) \quad \text{(Eq. 1)}$$

Where:

R_c = Coke burn-off rate, kg/hr (lb/hr);

Q_r = Volumetric flow rate of exhaust gas from catalyst regenerator before adding air or gas streams. Example: You may measure upstream or downstream of an electrostatic precipitator, but you must measure upstream of a carbon monoxide boiler, dscm/min (dscf/min). You may use the alternative in either § 63.1573(a)(1) or (2), as applicable, to calculate Qr;

Q_a = Volumetric flow rate of air to catalytic cracking unit catalyst regenerator, as determined from instruments in the catalytic cracking unit control room, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in regenerator exhaust, percent by volume (dry basis);

%CO = Carbon monoxide concentration in regenerator exhaust, percent by volume (dry basis);

$\%O_2$ = Oxygen concentration in regenerator exhaust, percent by volume (dry basis);

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) (0.0186 (lb-min)/(hr-dscf-%));

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) (0.1303 (lb-min)/(hr-dscf));

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) (0.0062 (lb-min)/(hr-dscf-%));

Q_{oxy} = Volumetric flow rate of oxygen-enriched air stream to regenerator, as determined from instruments in the catalytic cracking unit control room, dscm/min (dscf/min); and

$\%O_{xy}$ = Oxygen concentration in oxygen-enriched air stream, percent by volume (dry basis).

$$E = \frac{K \times C_s \times Q_{sd}}{R_c} \qquad \text{(Eq. 2)}$$

Where:

E = Emission rate of PM, kg/1,000 kg (lb/1,000 lb) of coke burn-off;

C_s = Concentration of PM, g/dscm (lb/dscf);

Q_{sd} = Volumetric flow rate of the catalytic cracking unit catalyst regenerator flue gas as measured by Method 2 in appendix A–1 to part 60 of this chapter, dscm/hr (dscf/hr);

R_c = Coke burn-off rate, kg coke/hr (1,000 lb coke/hr); and

K = Conversion factor, 1.0 (kg^2/g)/(1,000 kg) (1,000 lb/(1,000 lb)).

$$E_s = 1.0 + A\left(\frac{H}{R_c}\right)K' \qquad \text{(Eq. 3)}$$

Where:

E_s = Emission rate of PM allowed, kg/1,000 kg (1b/1,000 lb) of coke burn-off in catalyst regenerator;

1.0 = Emission limitation, kg coke/1,000 kg (lb coke/1,000 lb);

A = Allowable incremental rate of PM emissions. Before August 1, 2017, A = 0.18 g/million cal (0.10 lb/million Btu). On or after August 1, 2017, A = 0 g/million cal (0 lb/million Btu);

H = Heat input rate from solid or liquid fossil fuel, million cal/hr (million Btu/hr). Make sure your permitting authority approves procedures for determining the heat input rate;

R_c = Coke burn-off rate, kg coke/hr (1,000 lb coke/hr) determined using Equation 1 of this section; and

K′ = Conversion factor to units to standard, 1.0 (kg_2/g)/(1,000 kg) (10_3 lb/(1,000 lb)).

$$Opacity\ Limit = Opacity_{st} \times \left(\frac{1\,\text{lb}/1000\,\text{lb coke burn}}{PMEmR_{st}}\right) \qquad \text{(Eq. 4)}$$

Where:

Opacity Limit = Maximum permissible hourly average opacity, percent, or 10 percent, whichever is greater;

$Opacity_{st}$ = Hourly average opacity measured during the source test, percent; and

$PMEmR_{st}$ = PM emission rate measured during the source test, lb/1,000 lb coke burn.

(ii) If you elect Option 1c in paragraph (a)(1)(iii) of this section, the PM concentration emission limit, determine the average PM concentration from the initial performance test used to certify your PM CEMS.

* * * * *

(iv) If you elect Option 4 in paragraph (a)(1)(vi) of this section, the Ni per coke burn-off emission limit, compute your Ni emission rate using Equations 1 and 8 of this section and your site-specific Ni operating limit (if you use a continuous opacity monitoring system) using Equations 9 and 10 of this section as follows:

$$E_{Ni_2} = \frac{C_{Ni} \times Q_{sd}}{R_c} \qquad \text{(Eq. 8)}$$

Where:

E_{Ni2} = Normalized mass emission rate of Ni, mg/kg coke (lb/1,000 lb coke).

$$Opacity_2 = \frac{1.0\,\text{mg/kg coke}}{NiEmR2_{st}} \times Opacity_{st} \qquad \text{(Eq. 9)}$$

Where:

$Opacity_2$ = Opacity value for use in Equation 10 of this section, percent, or 10 percent, whichever is greater; and

$NiEmR2_{st}$ = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 8 of this section for each of the performance test runs, mg/kg coke.

$$Ni\ Operating\ Limit_2 = Opacity_2 \times E\text{-}Cat_{st} \times \frac{Q_{mon,st}}{R_{c,st}} \qquad \text{(Eq. 10)}$$

Where:

Ni Operating $Limit_2$ = Maximum permissible hourly average Ni operating limit, percent-ppmw-acfm-hr/kg coke, *i.e.*, your site-specific Ni operating limit; and

$R_{c,st}$ = Coke burn rate from Equation 1 of this section, as measured during the initial performance test, kg coke/hr.

* * * * *

(c) * * *

(5) If you elect to comply with the alternative limit in paragraph (a)(5)(ii) of this section during periods of startup, shutdown, and hot standby, demonstrate continuous compliance by:

(i) Collecting the volumetric flow rate from the catalyst regenerator (in acfm) and determining the average flow rate for each hour. For events lasting less than one hour, determine the average flow rate during the event.

(ii) Determining the cumulative cross-sectional area of the primary internal cyclone inlets in square feet (ft^2) using design drawings of the primary (first-stage) internal cyclones to determine the inlet cross-sectional area of each primary internal cyclone and summing the cross-sectional areas for all primary internal cyclones in the catalyst regenerator or, if primary cyclones. If all primary internal cyclones are identical, you may alternatively determine the inlet cross-sectional area of one primary internal cyclone using design drawings and multiply that area by the total number of primary internal cyclones in the catalyst regenerator.

(iii) Calculating the inlet velocity to the primary internal cyclones in square feet per second (ft^2/sec) by dividing the average volumetric flow rate (acfm) by the cumulative cross-sectional area of the primary internal cyclone inlets (ft^2) and by 60 seconds/minute (for unit conversion).

(iv) Maintaining the inlet velocity to the primary internal cyclones at or above 20 feet per second for each hour during the startup, shutdown, or hot standby event or, for events lasting less than 1 hour, for the duration of the event.

■ 41. Section 63.1565 is amended by revising paragraph (a)(1) introductory text and adding paragraph (a)(5) to read as follows:

§ 63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?

(a) * * *

(1) Except as provided in paragraph (a)(5) of this section, meet each emission limitation in Table 8 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for carbon monoxide (CO) in § 60.103 of this chapter or is subject to § 60.102a(b)(4) of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit is not subject to the NSPS for CO, you can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

* * * * *

(5) During periods of startup, shutdown and hot standby, you can choose from the two options in paragraphs (a)(5)(i) and (ii) of this section:

(i) You can elect to comply with the requirements in paragraphs (a)(1) and (2) of this section; or

(ii) You can elect to maintain the oxygen (O_2) concentration in the exhaust gas from your catalyst regenerator at or above 1 volume percent (dry basis).

* * * * *

■ 42. Section 63.1566 is amended by revising paragraphs (a)(1) introductory text, (a)(1)(i), and (a)(4) to read as follows:

§ 63.1566 What are my requirements for organic HAP emissions from catalytic reforming units?

(a) * * *

(1) Meet each emission limitation in Table 15 of this subpart that applies to you. You can choose from the two options in paragraphs (a)(1)(i) and (ii) of this section.

(i) You can elect to vent emissions of total organic compounds (TOC) to a flare (Option 1). On and after January 30, 2019, the flare must meet the requirements of § 63.670. Prior to January 30, 2019, the flare must meet the control device requirements in § 63.11(b) or the requirements of § 63.670.

* * * * *

(4) The emission limitations in Tables 15 and 16 of this subpart do not apply to emissions from process vents during passive depressuring when the reactor vent pressure is 5 pounds per square inch gauge (psig) or less. The emission limitations in Tables 15 and 16 of this subpart do apply to emissions from process vents during active purging operations (when nitrogen or other purge gas is actively introduced to the reactor vessel) or active depressuring (using a vacuum pump, ejector system, or similar device) regardless of the reactor vent pressure.

* * * * *

■ 43. Section 63.1568 is amended by revising paragraphs (a)(1) introductory text and (a)(1)(i) and adding paragraph (a)(4) to read as follows:

§ 63.1568 What are my requirements for HAP emissions from sulfur recovery units?

(a) * * *

(1) Meet each emission limitation in Table 29 of this subpart that applies to you. If your sulfur recovery unit is subject to the NSPS for sulfur oxides in § 60.104 or § 60.102a(f)(1) of this chapter, you must meet the emission limitations for NSPS units. If your sulfur recovery unit is not subject to one of these NSPS for sulfur oxides, you can choose from the options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to meet the NSPS requirements in § 60.104(a)(2) or § 60.102a(f)(1) of this chapter (Option 1); or

* * * * *

(4) During periods of startup and shutdown, you can choose from the three options in paragraphs (a)(4)(i) through (iii) of this section.

(i) You can elect to comply with the requirements in paragraphs (a)(1) and (2) of this section.

(ii) You can elect to send any startup or shutdown purge gases to a flare. On and after January 30, 2019, the flare must meet the requirements of § 63.670. Prior to January 30, 2019, the flare must meet the design and operating requirements in § 63.11(b) or the requirements of § 63.670.

(iii) You can elect to send any startup or shutdown purge gases to a thermal oxidizer or incinerator operated at a minimum hourly average temperature of 1,200 degrees Fahrenheit in the firebox and a minimum hourly average outlet oxygen (O_2) concentration of 2 volume percent (dry basis).

* * * * *

■ 44. Section 63.1570 is amended by revising paragraphs (a) through (d) and removing paragraph (g) to read as follows:

§ 63.1570 What are my general requirements for complying with this subpart?

(a) You must be in compliance with all of the non-opacity standards in this subpart at all times.

(b) You must be in compliance with the opacity and visible emission limits in this subpart at all times.

(c) At all times, you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(d) During the period between the compliance date specified for your affected source and the date upon which continuous monitoring systems have been installed and validated and any applicable operating limits have been set, you must maintain a log that documents the procedures used to minimize emissions from process and emissions control equipment according to the general duty in paragraph (c) of this section.

* * * * *

■ 45. Section 63.1571 is amended by:

■ a. Adding paragraphs (a)(5) and (6);

■ b. Revising paragraph (b)(1);

■ c. Removing paragraph (b)(4);

■ d. Redesignating paragraph (b)(5) as paragraph (b)(4); and

■ e. Revising the first sentence of paragraph (d)(2) and paragraph (d)(4).

The revisions and additions read as follows:

§ 63.1571 How and when do I conduct a performance test or other initial compliance demonstration?

(a) * * *

(5) *Periodic performance testing for PM or Ni.* Except as provided in paragraphs (a)(5)(i) and (ii) of this section, conduct a periodic performance test for PM or Ni for each catalytic cracking unit at least once every 5 years according to the requirements in Table 4 of this subpart. You must conduct the first periodic performance test no later than August 1, 2017.

(i) Catalytic cracking units monitoring PM concentration with a PM CEMS are not required to conduct a periodic PM performance test.

(ii) Conduct a performance test annually if you comply with the emission limits in Item 1 (NSPS subpart J) or Item 4 (Option 1a) in Table 1 of this subpart and the PM emissions measured during the most recent performance source test are greater than 0.80 g/kg coke burn-off.

(6) *One-time performance testing for HCN.* Conduct a performance test for HCN from each catalytic cracking unit no later than August 1, 2017 according to the applicable requirements in paragraphs (a)(6)(i) and (ii) of this section.

(i) If you conducted a performance test for HCN for a specific catalytic cracking unit between March 31, 2011 and February 1, 2016, you may submit a request to the Administrator to use the previously conducted performance test results to fulfill the one-time performance test requirement for HCN for each of the catalytic cracking units tested according to the requirements in paragraphs (a)(6)(i)(A) through (D) of this section.

(A) The request must include a copy of the complete source test report, the date(s) of the performance test and the test methods used. If available, you must also indicate whether the catalytic cracking unit catalyst regenerator was operated in partial or complete combustion mode during the test, the control device configuration, including whether platinum or palladium combustion promoters were used during the test, and the CO concentration (measured using CO CEMS or manual test method) for each test run.

(B) You must submit a separate request for each catalytic cracking unit tested and you must submit each request to the Administrator no later than March 30, 2016.

(C) The Administrator will evaluate each request with respect to the completeness of the request, the completeness of the submitted test report and the appropriateness of the test methods used. The Administrator will notify the facility within 60 days of receipt of the request if it is approved or denied. If the Administrator fails to respond to the facility within 60 days of receipt of the request, the request will be automatically approved.

(D) If the request is approved, you do not need to conduct an additional HCN performance test. If the request is denied, you must conduct an additional HCN performance test following the requirements in (a)(6)(ii) of this section.

(ii) Unless you receive approval to use a previously conducted performance test to fulfill the one-time performance test requirement for HCN for your catalytic cracking unit as provided in paragraph (a)(6)(i) of this section, conduct a performance test for HCN for each catalytic cracking unit no later than August 1, 2017 according to following requirements:

(A) Select sampling port location, determine volumetric flow rate, conduct gas molecular weight analysis and measure moisture content as specified in either Item 1 of Table 4 of this subpart or Item 1 of Table 11 of this subpart.

(B) Measure HCN concentration using Method 320 of appendix A of this part. The method ASTM D6348–03 (Reapproved 2010) including Annexes A1 through A8 (incorporated by reference—see § 63.14) is an acceptable alternative to EPA Method 320 of appendix A of this part. The method ASTM D6348–12e1 (incorporated by reference—see § 63.14) is an acceptable alternative to EPA Method 320 of appendix A of this part with the following two caveats:

(*1*) The test plan preparation and implementation in the Annexes to ASTM D6348–03 (Reapproved 2010), Sections A1 through A8 are mandatory; and

(*2*) In ASTM D6348–03 (Reapproved 2010) Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5). In order for the test data to be acceptable for a compound, %R must be 70% ≥ R ≤ 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 Result = (Measured Concentration in the Stack × 100÷/ % R.

(C) Measure CO concentration as specified in either Item 2 or 3a of Table 11 of this subpart.

(D) Record and include in the test report an indication of whether the catalytic cracking unit catalyst regenerator was operated in partial or complete combustion mode and the control device configuration, including whether platinum or palladium combustion promoters were used during the test.

(b) * * *

(1) Performance tests shall be conducted according to the provisions of § 63.7(e) except that performance tests shall be conducted at maximum representative operating capacity for the process. During the performance test, you must operate the control device at either maximum or minimum representative operating conditions for monitored control device parameters, whichever results in lower emission reduction. You must not conduct a performance test during startup, shutdown, periods when the control device is bypassed or periods when the process, monitoring equipment or control device is not operating properly. You may not conduct performance tests during periods of malfunction. You must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that the test was conducted at maximum representative operating capacity. Upon request, you must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

* * * * *

(d) * * *

(2) If you must meet the HAP metal emission limitations in § 63.1564, you elect the option in paragraph (a)(1)(iv) in § 63.1564 (Ni per coke burn-off), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration from the initial performance test. * * *

* * * * *

(4) Except as specified in paragraph (d)(3) of this section, if you use continuous parameter monitoring systems, you may adjust one of your monitored operating parameters (flow rate, total power and secondary current, pressure drop, liquid-to-gas ratio) from the average of measured values during the performance test to the maximum value (or minimum value, if applicable) representative of worst-case operating conditions, if necessary. This adjustment of measured values may be done using control device design specifications, manufacturer recommendations, or other applicable information. You must provide supporting documentation and rationale in your Notification of Compliance Status, demonstrating to the satisfaction of your permitting authority, that your affected source complies with the applicable emission limit at the operating limit based on adjusted values.

* * * * *

■ 46. Section 63.1572 is amended by revising paragraphs (c) introductory text, (c)(1), (3), and (4) and (d)(1) and (2) to read as follows:

§ 63.1572 What are my monitoring installation, operation, and maintenance requirements?

* * * * *

(c) Except for flare monitoring systems, you must install, operate, and maintain each continuous parameter monitoring system according to the requirements in paragraphs (c)(1) through (5) of this section. For flares, on and after January 30, 2019, you must install, operate, calibrate, and maintain monitoring systems as specified in §§ 63.670 and 63.671. Prior to January 30, 2019, you must either meet the monitoring system requirements in paragraphs (c)(1) through (5) of this section or meet the requirements in §§ 63.670 and 63.671.

(1) You must install, operate, and maintain each continuous parameter monitoring system according to the requirements in Table 41 of this subpart. You must also meet the equipment specifications in Table 41 of this subpart if pH strips or colormetric tube sampling systems are used. You must install, operate, and maintain each continuous parameter monitoring system according to the requirements in Table 41 of this subpart. You must meet the requirements in Table 41 of this subpart for BLD systems. Alternatively, before August 1, 2017, you may install, operate, and maintain each continuous parameter monitoring system in a manner consistent with the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately.

* * * * *

(3) Each continuous parameter monitoring system must have valid hourly average data from at least 75 percent of the hours during which the process operated, except for BLD systems.

(4) Each continuous parameter monitoring system must determine and record the hourly average of all recorded readings and if applicable, the daily average of all recorded readings for each operating day, except for BLD systems. The daily average must cover a 24-hour period if operation is continuous or the number of hours of operation per day if operation is not continuous, except for BLD systems.

* * * * *

(d) * * *

(1) You must conduct all monitoring in continuous operation (or collect data at all required intervals) at all times the affected source is operating.

(2) You may not use data recorded during required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments) for purposes of this regulation, including data averages and calculations, for fulfilling a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

■ 47. Section 63.1573 is amended by:

■ a. Redesignating paragraphs (b), (c), (d), (e), and (f) as paragraphs (c), (d), (e), (f), and (g);

■ b. Adding paragraph (b); and

■ c. Revising newly redesignated paragraphs (c) introductory text, (d) introductory text, (f) introductory text, and (g)(1) introductory text.

The revisions and additions read as follows:

§ 63.1573 What are my monitoring alternatives?

* * * * *

(b) *What is the approved alternative for monitoring pressure drop?* You may use this alternative to a continuous parameter monitoring system for pressure drop if you operate a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles. You shall:

(1) Conduct a daily check of the air or water pressure to the spray nozzles;

(2) Maintain records of the results of each daily check; and

(3) Repair or replace faulty (*e.g.,* leaking or plugged) air or water lines within 12 hours of identification of an abnormal pressure reading.

(c) *What is the approved alternative for monitoring pH or alkalinity levels?* You may use the alternative in paragraph (c)(1) or (2) of this section for a catalytic reforming unit.

* * * * *

(d) *Can I use another type of monitoring system?* You may use an automated data compression system. An automated data compression system does not record monitored operating parameter values at a set frequency (*e.g.,* once every hour) but records all values that meet set criteria for variation from previously recorded values. You must maintain a record of the description of the monitoring system and data recording system, including the criteria used to determine which monitored values are recorded and retained, the method for calculating daily averages, and a demonstration that the system meets all of the criteria in paragraphs (d)(1) through (5) of this section:

* * * * *

(f) *How do I request to monitor alternative parameters?* You must submit a request for review and approval or disapproval to the Administrator. The request must include the information in paragraphs (f)(1) through (5) of this section.

* * * * *

(g) * * *

(1) You may request alternative monitoring requirements according to the procedures in this paragraph if you meet each of the conditions in paragraphs (g)(1)(i) through (iii) of this section:

* * * * *

■ 48. Section 63.1574 is amended by revising paragraphs (a)(3) introductory text and (f)(1) to read as follows:

§ 63.1574 What notifications must I submit and when?

(a) * * *

(3) If you are required to conduct an initial performance test, performance evaluation, design evaluation, opacity observation, visible emission observation, or other initial compliance demonstration, you must submit a notification of compliance status according to § 63.9(h)(2)(ii). You can submit this information in an operating permit application, in an amendment to an operating permit application, in a separate submission, or in any combination. In a State with an approved operating permit program where delegation of authority under section 112(l) of the CAA has not been requested or approved, you must provide a duplicate notification to the applicable Regional Administrator. If the required information has been submitted previously, you do not have to provide a separate notification of compliance status. Just refer to the earlier submissions instead of duplicating and resubmitting the previously submitted information.

* * * * *

(f) * * *

(1) You must submit the plan to your permitting authority for review and approval along with your notification of compliance status. While you do not have to include the entire plan in your permit under part 70 or 71 of this chapter, you must include the duty to prepare and implement the plan as an applicable requirement in your part 70 or 71 operating permit. You must submit any changes to your permitting authority for review and approval and comply with the plan as submitted until the change is approved.

* * * * *

■ 49. Section 63.1575 is amended by:

■ a. Revising paragraphs (d) introductory text and (d)(1) and (2);

■ b. Adding paragraph (d)(4);

■ c. Revising paragraph (e) introductory text;

■ d. Removing and reserving paragraph (e)(1);

■ e. Revising paragraphs (e)(4) and (6) and (f)(1) and (2);

■ f. Removing and reserving paragraph (h); and

■ g. Adding paragraph (k).

The revisions and additions read as follows:

§ 63.1575 What reports must I submit and when?

* * * * *

(d) For each deviation from an emission limitation and for each deviation from the requirements for work practice standards that occurs at an affected source where you are not using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation or work practice standard in this subpart, the semiannual compliance report must contain the information in paragraphs (c)(1) through (3) of this section and the information in paragraphs (d)(1) through (4) of this section.

(1) The total operating time of each affected source during the reporting period and identification of the sources for which there was a deviation.

(2) Information on the number, date, time, duration, and cause of deviations (including unknown cause, if applicable).

* * * * *

(4) The applicable operating limit or work practice standard from which you deviated and either the parameter monitor reading during the deviation or a description of how you deviated from the work practice standard.

(e) For each deviation from an emission limitation occurring at an affected source where you are using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, you must include the information in paragraphs (c)(1) through (3) of this section, in paragraphs (d)(1) through (3) of this section, and in paragraphs (e)(2) through (13) of this section.

* * * * *

(4) An estimate of the quantity of each regulated pollutant emitted over the emission limit during the deviation, and a description of the method used to estimate the emissions.

* * * * *

(6) A breakdown of the total duration of the deviations during the reporting period and into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

* * * * *

(f) * * *

(1) You must include the information in paragraph (f)(1)(i) or (ii) of this section, if applicable.

(i) If you are complying with paragraph (k)(1) of this section, a summary of the results of any performance test done during the reporting period on any affected unit. Results of the performance test include the identification of the source tested, the date of the test, the percentage of emissions reduction or outlet pollutant concentration reduction (whichever is needed to determine compliance) for each run and for the average of all runs, and the values of the monitored operating parameters.

(ii) If you are not complying with paragraph (k)(1) of this section, a copy of any performance test done during the reporting period on any affected unit. The report may be included in the next semiannual compliance report. The copy must include a complete report for each test method used for a particular kind of emission point tested. For additional tests performed for a similar emission point using the same method, you must submit the results and any other information required, but a complete test report is not required. A complete test report contains a brief process description; a simplified flow diagram showing affected processes, control equipment, and sampling point locations; sampling site data; description of sampling and analysis procedures and any modifications to standard procedures; quality assurance procedures; record of operating conditions during the test; record of preparation of standards; record of calibrations; raw data sheets for field sampling; raw data sheets for field and laboratory analyses; documentation of calculations; and any other information required by the test method.

(2) Any requested change in the applicability of an emission standard (*e.g.,* you want to change from the PM standard to the Ni standard for catalytic cracking units or from the HCl concentration standard to percent reduction for catalytic reforming units) in your compliance report. You must include all information and data necessary to demonstrate compliance with the new emission standard selected and any other associated requirements.

* * * * *

(k) *Electronic submittal of performance test and CEMS performance evaluation data.* For performance tests or CEMS performance evaluations conducted on and after February 1, 2016, if required to submit the results of a performance test or CEMS performance evaluation, you must submit the results according to the procedures in paragraphs (k)(1) and (2) of this section.

(1) Within 60 days after the date of completing each performance test as required by this subpart, you must submit the results of the performance tests following the procedure specified in either paragraph (k)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic storage media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (k)(1)(i).

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation required by § 63.1571(a) and (b), you must submit the results of the performance evaluation following the procedure specified in either paragraph (k)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI is accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being submitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic storage media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (k)(2)(i).

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in § 63.13.

■ 50. Section 63.1576 is amended by revising paragraphs (a)(2) and (b)(3) and (5) to read as follows:

§ 63.1576 What records must I keep, in what form, and for how long?

(a) * * *

(2) The records specified in paragraphs (a)(2)(i) through (iv) of this section.

(i) Record the date, time, and duration of each startup and/or shutdown period, recording the periods when the affected source was subject to the standard applicable to startup and shutdown.

(ii) In the event that an affected unit fails to meet an applicable standard, record the number of failures. For each failure record the date, time and duration of each failure.

(iii) For each failure to meet an applicable standard, record and retain a list of the affected sources or equipment, an estimate of the volume of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.

(iv) Record actions taken to minimize emissions in accordance with § 63.1570(c) and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

* * * * *

(b) * * *

(3) The performance evaluation plan as described in § 63.8(d)(2) for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If the performance evaluation plan is revised, you must keep previous (*i.e.,* superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. The program of corrective action should be included in the plan required under § 63.8(d)(2).

* * * * *

(5) Records of the date and time that each deviation started and stopped.

* * * * *

■ 51. Section 63.1579 is amended by:

■ a. Revising the introductory text;

■ b. Adding, in alphabetical order, a new definition of ''Hot standby''; and

■ c. Revising the definitions of ''Deviation'' and ''PM''.

The revisions read as follows:

§ 63.1579 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in 40 CFR 63.2, the General Provisions of this part (§§ 63.1 through 63.15), and in this section as listed. If the same term is defined in subpart A of this part and in this section, it shall have the meaning given in this section for purposes of this subpart.

* * * * *

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limit, operating limit, or work practice standard; or

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

* * * * *

Hot standby means periods when the catalytic cracking unit is not receiving fresh or recycled feed oil but the catalytic cracking unit is maintained at elevated temperatures, typically using torch oil in the catalyst regenerator and recirculating catalyst, to prevent a complete shutdown and cold restart of the catalytic cracking unit.

* * * * *

PM means, for the purposes of this subpart, emissions of particulate matter that serve as a surrogate measure of the total emissions of particulate matter and metal HAP contained in the particulate matter, including but not limited to: Antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium as measured by Methods 5, 5B or 5F in appendix A–3 to part 60 of this chapter or by an approved alternative method.

* * * * *

■ 52. Table 1 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1564(a)(1), you shall meet each emission limitation in the following table that applies to you.

TABLE 1 TO SUBPART UUU OF PART 63—METAL HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

For each new or existing catalytic cracking unit . . .	You shall meet the following emission limits for each catalyst regenerator vent . . .
1. Subject to new source performance standard (NSPS) for PM in 40 CFR 60.102 and not electing § 60.100(e).	PM emissions must not exceed 1.0 gram per kilogram (g/kg) (1.0 lb/1,000 lb) of coke burn-off, and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. Before August 1, 2017, if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or in supplemental liquid or solid fossil fuel, the incremental rate of PM emissions must not exceed 43.0 grams per Gigajoule (g/GJ) or 0.10 pounds per million British thermal units (lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i); or 40 CFR 60.102 and electing § 60.100(e).	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off or, if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii)	PM emissions must not exceed 0.5 g/kg coke burn-off (0.5 lb/1000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air.
4. Option 1a: Elect NSPS subpart J requirements for PM per coke burn limit and 30% opacity, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM emissions must not exceed the limits specified in Item 1 of this table.
5. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1000 lb) of coke burn-off.
6. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM emissions must not exceed 0.040 gr/dscf corrected to 0 percent excess air.
7. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1000 lb) of coke burn-off in the catalyst regenerator.
8. Option 3: Ni lb/hr limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	Nickel (Ni) emissions must not exceed 13,000 milligrams per hour (mg/hr) (0.029 lb/hr).
9. Option 4: Ni per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	Ni emissions must not exceed 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator.

■ 53. Table 2 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1564(a)(2), you shall meet each operating limit in the following table that applies to you.

TABLE 2 TO SUBPART UUU OF PART 63—OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
1. Subject to the NSPS for PM in 40 CFR 60.102 and not electing § 60.100(e).	Continuous opacity monitoring system.	Any	Maintain the 3-hour rolling average opacity of emissions from your catalyst regenerator vent no higher than 20 percent.

TABLE 2 TO SUBPART UUU OF PART 63—OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i) or electing § 60.100(e).	a. PM CEMS	Any	Not applicable.
	b. Continuous opacity monitoring system used to comply with a site-specific opacity limit.	Cyclone or electrostatic precipitator.	Maintain the 3-hour rolling average opacity of emissions from your catalyst regenerator vent no higher than the site-specific opacity limit established during the performance test.
	c. Continuous parameter monitoring systems.	Electrostatic precipitator	i. Maintain the daily average coke burn-off rate or daily average flow rate no higher than the limit established in the performance test. ii. Maintain the 3-hour rolling average total power and secondary current above the limit established in the performance test.
	d. Continuous parameter monitoring systems.	Wet scrubber	i. Maintain the 3-hour rolling average liquid-to-gas ratio above the limit established in the performance test. ii. Except for periods of startup, shutdown, and hot standby, maintain the 3-hour rolling average pressure drop above the limit established in the performance test.[1]
	e. Bag leak detection (BLD) system.	Fabric filter	Maintain particulate loading below the BLD alarm set point established in the initial adjustment of the BLD system or allowable seasonal adjustments.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii).	Any	Any	The applicable operating limits in Item 2 of this table.
4. Option 1a: Elect NSPS subpart J requirements for PM per coke burn limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	Any	Any	See Item 1 of this table.
5. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	Any	Any	The applicable operating limits in Item 2.b, 2.c, 2.d, and 2.e of this table.
6. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM CEMS	Any	Not applicable.
7. Option 2: PM per coke burn-off limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	a. Continuous opacity monitoring system used to comply with a site-specific opacity limit.	Cyclone, fabric filter, or electrostatic precipitator.	See Item 2.b of this table. Alternatively, before August 1, 2017, you may maintain the hourly average opacity of emissions from your catalyst generator vent no higher than the site-specific opacity limit established during the performance test.
	b. Continuous parameter monitoring systems.	i. Electrostatic precipitator	(1) See Item 2.c.i of this table. (2) See item 2.c.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average voltage and secondary current above the limit established in the performance test.

TABLE 2 TO SUBPART UUU OF PART 63—OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
		ii. Wet scrubber	(1) See Item 2.d.i of this table. Alternatively, before August 1, 2017, you may maintain the daily average liquid-to-gas ratio above the limit established in the performance test. (2) See Item 2.d.ii of the table. Alternatively, before August 1, 2017, you may maintain the daily average pressure drop above the limit established in the performance test (not applicable to a wet scrubber of the non-venturi jet-ejector design).
	c. Bag leak detection (BLD) system.	Fabric filter	See item 2.e of this table.
8. Option 3: Ni lb/hr limit not subject to the NSPS for PM in 40 CFR 60.102.	a. Continuous opacity monitoring system.	Cyclone, fabric filter, or electrostatic precipitator.	Maintain the 3-hour rolling average Ni operating value no higher than the limit established during the performance test. Alternatively, before August 1, 2017, you may maintain the daily average Ni operating value no higher than the limit established during the performance test.
	b. Continuous parameter monitoring systems.	i. Electrostatic precipitator	(1) See Item 2.c.i of this table. (2) Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test. (3) See Item 2.c.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average voltage and secondary current (or total power input) above the established during the performance test.
		ii. Wet scrubber	(1) Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test. (2) See Item 2.d.i of this table. Alternatively, before August 1, 2017, you may maintain the daily average liquid-to-gas ratio above the limit established during the performance test. (3) See Item 2.d.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average pressure drop above the limit established during the performance test (not applicable to a non-venturi wet scrubber of the jet-ejector design).
	c. Bag leak detection (BLD) system.	Fabric filter	See item 2.e of this table.

TABLE 2 TO SUBPART UUU OF PART 63—OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
9. Option 4: Ni per coke burn-off limit not subject to the NSPS for PM in 40 CFR 60.102.	a. Continuous opacity monitoring system.	Cyclone, fabric filter, or electrostatic precipitator.	Maintain the 3-hour rolling average Ni operating value no higher than Ni operating limit established during the performance test. Alternatively, before August 1, 2017, you may elect to maintain the daily average Ni operating value no higher than the Ni operating limit established during the performance test.
	b. Continuous parameter monitoring systems.	i. Electrostatic precipitator	(1) Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test. (2) See Item 2.c.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average voltage and secondary current (or total power input) above the limit established during the performance test.
		ii. Wet scrubber	(1) Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test. (2) See Item 2.d.i of this table. Alternatively, before August 1, 2017, you may maintain the daily average liquid-to-gas ratio above the limit established during the performance test. (3) See Item 2.d.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average pressure drop above the limit established during the performance test (not applicable to a non-venturi wet scrubber of the jet-ejector design).
	c. Bag leak detection (BLD) system.	Fabric filter	See item 2.e of this table.
10. During periods of startup, shutdown, or hot standby.	Any	Any	Meet the requirements in § 63.1564(a)(5).

[1] If you use a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles, you can use the alternative in § 63.1573(b), and comply with the daily inspections, recordkeeping, and repair provisions, instead of a continuous parameter monitoring system for pressure drop across the scrubber.

■ 54. Table 3 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1564(b)(1), you shall meet each requirement in the following table that applies to you.

TABLE 3 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

For each new or existing catalytic cracking unit . . .	If you use this type of control device for your vent . . .	You shall install, operate, and maintain a . . .
1. Subject to the NSPS for PM in 40 CFR 60.102 and not electing § 60.100(e).	Any	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent.

TABLE 3 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit . . .	If you use this type of control device for your vent . . .	You shall install, operate, and maintain a . . .
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i); or in § 60.102 and electing § 60.100(e); electing to meet the PM per coke burn-off limit.	a. Cyclone	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent.
	b. Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the coke burn-off rate or the gas flow rate entering or exiting the control device,[1] the voltage, current, and secondary current to the control device.
	c. Wet scrubber	Continuous parameter monitoring system to measure and record the pressure drop across the scrubber,[2] the coke burn-off rate or the gas flow rate entering or exiting the control device,[3] and total liquid (or scrubbing liquor) flow rate to the control device.
	d. Fabric Filter	Continuous bag leak detection system to measure and record increases in relative particulate loading from each catalyst regenerator vent.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i); or in § 60.102 and electing § 60.100(e); electing to meet the PM concentration limit.	Any	Continuous emission monitoring system to measure and record the concentration of PM and oxygen from each catalyst regenerator vent.
4. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii) electing to meet the PM per coke burn-off limit.	Any	The applicable continuous monitoring systems in item 2 of this table.
5. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii) electing to meet the PM concentration limit.	Any	See item 3 of this table.
6. Option 1a: Elect NSPS subpart J, PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.120a(b)(1).	Any	See item 1 of this table.
7. Option 1b: Elect NSPS subpart Ja, PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.120a(b)(1).	Any	The applicable continuous monitoring systems in item 2 of this table.
8. Option 1c: Elect NSPS subpart Ja, PM concentration limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.120a(b)(1).	Any	See item 3 of this table.
9. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.120a(b)(1).	Any	The applicable continuous monitoring systems in item 2 of this table.
10. Option 3: Ni lb/hr limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	a. Cyclone	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device.[1]
	b. Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device[1]; or continuous parameter monitoring systems to measure and record the coke burn-off rate or the gas flow rate entering or exiting the control device[1] and the voltage and current (to measure the total power to the system) and secondary current to the control device.
	c. Wet scrubber	Continuous parameter monitoring system to measure and record the pressure drop across the scrubber,[2] gas flow rate entering or exiting the control device,[1] and total liquid (or scrubbing liquor) flow rate to the control device.
	d. Fabric Filter	Continuous bag leak detection system to measure and record increases in relative particulate loading from each catalyst regenerator vent or the monitoring systems specified in item 10.a of this table.
11. Option 4: Ni per coke burn-off limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	a. Cyclone	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the coke burn-off rate and the gas flow rate entering or exiting the control device.[1]

TABLE 3 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit . . .	If you use this type of control device for your vent . . .	You shall install, operate, and maintain a . . .
	b. Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the coke burn-off rate and the gas flow rate entering or exiting the control device [1]; or continuous parameter monitoring systems to measure and record the coke burn-off rate or the gas flow rate entering or exiting the control device [1] and voltage and current (to measure the total power to the system) and secondary current to the control device.
	c. Wet scrubber	Continuous parameter monitoring system to measure and record the pressure drop across the scrubber,[2] gas flow rate entering or exiting the control device,[1] and total liquid (or scrubbing liquor) flow rate to the control device.
	d. Fabric Filter	Continuous bag leak detection system to measure and record increases in relative particulate loading from each catalyst regenerator vent or the monitoring systems specified in item 11.a of this table.
12. Electing to comply with the operating limits in § 63.1566(a)(5)(iii) during periods of startup, shutdown, or hot standby.	Any	Continuous parameter monitoring system to measure and record the gas flow rate exiting the catalyst regenerator.[1]

[1] If applicable, you can use the alternative in § 63.1573(a)(1) instead of a continuous parameter monitoring system for gas flow rate.

[2] If you use a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles, you can use the alternative in § 63.1573(b) instead of a continuous parameter monitoring system for pressure drop across the scrubber.

■ 55. Table 4 to subpart UUU of part 63 is revised to read as follows:

As stated in §§ 63.1564(b)(2) and 63.1571(a)(5), you shall meet each requirement in the following table that applies to you.

TABLE 4 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	You must . . .	Using . . .	According to these requirements . . .
1. Any	a. Select sampling port's location and the number of traverse ports.	Method 1 or 1A in appendix A–1 to part 60 of this chapter.	Sampling sites must be located at the outlet of the control device or the outlet of the regenerator, as applicable, and prior to any releases to the atmosphere.
	b. Determine velocity and volumetric flow rate.	Method 2, 2A, 2C, 2D, or 2F in appendix A–1 to part 60 of this chapter, or Method 2G in appendix A–2 to part 60 of this chapter, as applicable.	
	c. Conduct gas molecular weight analysis.	Method 3, 3A, or 3B in appendix A–2 to part 60 of this chapter, as applicable.	
	d. Measure moisture content of the stack gas.	Method 4 in appendix A–3 to part 60 of this chapter.	
	e. If you use an electrostatic precipitator, record the total number of fields in the control system and how many operated during the applicable performance test.		
	f. If you use a wet scrubber, record the total amount (rate) of water (or scrubbing liquid) and the amount (rate) of make-up liquid to the scrubber during each test run.		

TABLE 4 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	You must . . .	Using . . .	According to these requirements . . .
2. Subject to the NSPS for PM in 40 CFR 60.102 and not elect § 60.100(e).	a. Measure PM emissions	Method 5, 5B, or 5F (40 CFR part 60, appendix A–3) to determine PM emissions and associated moisture content for units without wet scrubbers. Method 5 or 5B (40 CFR part 60, appendix A–3) to determine PM emissions and associated moisture content for unit with wet scrubber.	You must maintain a sampling rate of at least 0.15 dry standard cubic meters per minute (dscm/min) (0.53 dry standard cubic feet per minute (dscf/min)).
	b. Compute coke burn-off rate and PM emission rate (lb/1,000 lb of coke burn-off).	Equations 1, 2, and 3 of § 63.1564 (if applicable).	
	c. Measure opacity of emissions	Continuous opacity monitoring system.	You must collect opacity monitoring data every 10 seconds during the entire period of the Method 5, 5B, or 5F performance test and reduce the data to 6-minute averages.
3. Subject to the NSPS for PM in 40 CFR 60.102a(b)(1) or elect § 60.100(e), electing the PM for coke burn-off limit.	a. Measure PM emissions	Method 5, 5B, or 5F (40 CFR part 60, appendix A–3) to determine PM emissions and associated moisture content for units without wet scrubbers. Method 5 or 5B (40 CFR part 60, appendix A–3) to determine PM emissions and associated moisture content for unit with wet scrubber.	You must maintain a sampling rate of at least 0.15 dscm/min (0.53 dscf/min).
	b. Compute coke burn-off rate and PM emission rate (lb/1,000 lb of coke burn-off).	Equations 1, 2, and 3 of § 63.1564 (if applicable).	
	c. Establish site-specific limit if you use a COMS.	Continuous opacity monitoring system.	If you elect to comply with the site-specific opacity limit in § 63.1564(b)(4)(i), you must collect opacity monitoring data every 10 seconds during the entire period of the Method 5, 5B, or 5F performance test. For site specific opacity monitoring, reduce the data to 6-minute averages; determine and record the average opacity for each test run; and compute the site-specific opacity limit using Equation 4 of § 63.1564.
4. Subject to the NSPS for PM in 40 CFR 60.102a(b)(1) or elect § 60.100(e).	a. Measure PM emissions	Method 5, 5B, or 5F (40 CFR part 60, appendix A–3) to determine PM emissions and associated moisture content for units without wet scrubbers. Method 5 or 5B (40 CFR part 60, appendix A–3) to determine PM emissions and associated moisture content for unit with wet scrubber.	You must maintain a sampling rate of at least 0.15 dscm/min (0.53 dscf/min).
5. Option 1a: Elect NSPS subpart J requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	See item 2 of this table.		
6. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	See item 3 of this table.		

TABLE 4 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	You must . . .	Using . . .	According to these requirements . . .
7. Option 1c: Elect NSPS requirements for PM concentration, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	See item 4 of this table.		
8. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	See item 3 of this table.		
9. Option 3: Ni lb/hr limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	a. Measure concentration of Ni	Method 29 (40 CFR part 60, appendix A–8).	
	b. Compute Ni emission rate (lb/hr).	Equation 5 of § 63.1564.	
	c. Determine the equilibrium catalyst Ni concentration.	XRF procedure in appendix A to this subpart1; or EPA Method 6010B or 6020 or EPA Method 7520 or 7521 in SW–8462; or an alternative to the SW–846 method satisfactory to the Administrator.	You must obtain 1 sample for each of the 3 test runs; determine and record the equilibrium catalyst Ni concentration for each of the 3 samples; and you may adjust the laboratory results to the maximum value using Equation 2 of § 63.1571.
	d. If you use a continuous opacity monitoring system, establish your site-specific Ni operating limit.	i. Equations 6 and 7 of § 63.1564 using data from continuous opacity monitoring system, gas flow rate, results of equilibrium catalyst Ni concentration analysis, and Ni emission rate from Method 29 test.	(1) You must collect opacity monitoring data every 10 seconds during the entire period of the initial Ni performance test; reduce the data to 6-minute averages; and determine and record the average opacity from all the 6-minute averages for each test run. (2) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial Ni performance test; measure the gas flow as near as practical to the continuous opacity monitoring system; and determine and record the hourly average actual gas flow rate for each test run.
10. Option 4: Ni per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	a. Measure concentration of Ni.	Method 29 (40 CFR part 60, appendix A–8).	
	b. Compute Ni emission rate (lb/1,000 lb of coke burn-off).	Equations 1 and 8 of § 63.1564.	
	c. Determine the equilibrium catalyst Ni concentration.	See item 6.c. of this table	You must obtain 1 sample for each of the 3 test runs; determine and record the equilibrium catalyst Ni concentration for each of the 3 samples; and you may adjust the laboratory results to the maximum value using Equation 2 of § 63.1571.
	d. If you use a continuous opacity monitoring system, establish your site-specific Ni operating limit.	i. Equations 9 and 10 of § 63.1564 with data from continuous opacity monitoring system, coke burn-off rate, results of equilibrium catalyst Ni concentration analysis, and Ni emission rate from Method 29 test.	(1) You must collect opacity monitoring data every 10 seconds during the entire period of the initial Ni performance test; reduce the data to 6-minute averages; and determine and record the average opacity from all the 6-minute averages for each test run.

TABLE 4 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	You must . . .	Using . . .	According to these requirements . . .
			(2) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial Ni performance test; measure the gas flow rate as near as practical to the continuous opacity monitoring system; and determine and record the hourly average actual gas flow rate for each test run.
	e. Record the catalyst addition rate for each test and schedule for the 10-day period prior to the test.		
11. If you elect item 5 Option 1b in Table 1, item 7 Option 2 in Table 1, item 8 Option 3 in Table 1, or item 9 Option 4 in Table 1 of this subpart and you use continuous parameter monitoring systems.	a. Establish each operating limit in Table 2 of this subpart that applies to you.	Data from the continuous parameter monitoring systems and applicable performance test methods.	
	b. Electrostatic precipitator or wet scrubber: Gas flow rate.	i. Data from the continuous parameter monitoring systems and applicable performance test methods.	(1) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial performance test; determine and record the average gas flow rate for each test run. (2) You must determine and record the 3-hr average gas flow rate from the test runs. Alternatively, before August 1, 2017, you may determine and record the maximum hourly average gas flow rate from all the readings.
	c. Electrostatic precipitator: Total power (voltage and current) and secondary current.	i. Data from the continuous parameter monitoring systems and applicable performance test methods.	(1) You must collect voltage, current, and secondary current monitoring data every 15 minutes during the entire period of the performance test; and determine and record the average voltage, current, and secondary current for each test run. Alternatively, before August 1, 2017, you may collect voltage and secondary current (or total power input) monitoring data every 15 minutes during the entire period of the initial performance test. (2) You must determine and record the 3-hr average total power to the system for the test runs and the 3-hr average secondary current from the test runs. Alternatively, before August 1, 2017, you may determine and record the minimum hourly average voltage and secondary current (or total power input) from all the readings.

TABLE 4 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	You must . . .	Using . . .	According to these requirements . . .
	d. Electrostatic precipitator or wet scrubber: Equilibrium catalyst Ni concentration.	Results of analysis for equilibrium catalyst Ni concentration.	You must determine and record the average equilibrium catalyst Ni concentration for the 3 runs based on the laboratory results. You may adjust the value using Equation 1 or 2 of § 63.1571 as applicable.
	e. Wet scrubber: Pressure drop (not applicable to non-venturi scrubber of jet ejector design).	i. Data from the continuous parameter monitoring systems and applicable performance test methods.	(1) You must collect pressure drop monitoring data every 15 minutes during the entire period of the initial performance test; and determine and record the average pressure drop for each test run. (2) You must determine and record the 3-hr average pressure drop from the test runs. Alternatively, before August 1, 2017, you may determine and record the minimum hourly average pressure drop from all the readings.
	f. Wet scrubber: Liquid-to-gas ratio.	i. Data from the continuous parameter monitoring systems and applicable performance test methods.	(1) You must collect gas flow rate and total water (or scrubbing liquid) flow rate monitoring data every 15 minutes during the entire period of the initial performance test; determine and record the average gas flow rate for each test run; and determine the average total water (or scrubbing liquid) flow for each test run. (2) You must determine and record the hourly average liquid-to-gas ratio from the test runs. Alternatively, before August 1, 2017, you may determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate from all the readings. (3) You must determine and record the 3-hr average liquid-to-gas ratio. Alternatively, before August 1, 2017, you may determine and record the minimum liquid-to-gas ratio.
	g. Alternative procedure for gas flow rate.	i. Data from the continuous parameter monitoring systems and applicable performance test methods.	(1) You must collect air flow rate monitoring data or determine the air flow rate using control room instrumentation every 15 minutes during the entire period of the initial performance test. (2) You must determine and record the 3-hr average rate of all the readings from the test runs. Alternatively, before August 1, 2017, you may determine and record the hourly average rate of all the readings. (3) You must determine and record the maximum gas flow rate using Equation 1 of § 63.1573.

[1] Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure).

[2] EPA Method 6010B, Inductively Coupled Plasma-Atomic Emission Spectrometry, EPA Method 6020, Inductively Coupled Plasma-Mass Spectrometry, EPA Method 7520, Nickel Atomic Absorption, Direct Aspiration, and EPA Method 7521, Nickel Atomic Absorption, Direct Aspiration are included in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW–846, Revision 5 (April 1998). The SW–846 and Updates (document number 955–001–00000–1) are available for purchase from the Superintendent of Documents, U.S. Government Publishing Office, Washington, DC 20402, (202) 512–1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487–4650. Copies may be inspected at the EPA Docket Center, William Jefferson Clinton (WJC) West Building, (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street NW., Suite 700, Washington, DC.

■ 56. Table 5 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1564(b)(5), you shall meet each requirement in the following table that applies to you.

TABLE 5 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH METAL HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

For each new and existing catalytic cracking unit catalyst regenerator vent . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Subject to the NSPS for PM in 40 CFR 60.102 and not electing § 60.100(e).	PM emissions must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off, and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. Before August 1, 2017, if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ or 0.10 lb/million Btu of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period.	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance test to demonstrate initial compliance with the NSPS and the average hourly opacity is no more than 30 percent, except that one 6-minute average in any 1-hour period can exceed 30 percent. As part of the Notification of Compliance Status, you must certify that your vent meets the 30 percent opacity limit. As part of your Notification of Compliance Status, you certify that your continuous opacity monitoring system meets the requirements in § 63.1572.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i); or in § 60.102 and electing § 60.100(e); electing to meet the PM per coke burn-off limit.	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off.	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your BLD; CO_2, O_2, or CO monitor; or continuous opacity monitoring system meets the requirements in § 63.1572.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i), electing to meet the PM per coke burn-off limit.	PM emissions must not exceed 0.5 g/kg (0.5 lb PM/1,000 lb) of coke burn-off).	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your BLD; CO_2, O_2, or CO monitor; or continuous opacity monitoring system meets the requirements in § 63.1572.
4. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i), electing to meet the PM concentration limit.	If a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air.	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM concentration is less than or equal to 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your PM CEMS meets the requirements in § 63.1572.

TABLE 5 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH METAL HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS—Continued

For each new and existing catalytic cracking unit catalyst regenerator vent . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
5. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii), electing to meet the PM concentration limit.	If a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air.	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM concentration is less than or equal to 0.020 gr/dscf corrected to 0 percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your PM CEMS meets the requirements in § 63.1572.
6. Option 1a: Elect NSPS subpart J requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM emissions must not exceed 1.0 gram per kilogram (g/kg) (1.0 lb/1,000 lb) of coke burn-off, and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. Before August 1, 2017, PM emission must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period.	The average PM emission rate, measured using EPA Method 5, 5B, or 5F (for a unit without a wet scrubber) or 5 or 5B (for a unit with a wet scrubber) (40 CFR part 60, appendix A–3), over the period of the initial performance test, is no higher than 1.0 g/kg coke burn-off (1.0 lb/1,000 lb) in the catalyst regenerator. The PM emission rate is calculated using Equations 1, 2, and 3 of § 63.1564. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. The average hourly opacity is no more than 30 percent, except that one 6-minute average in any 1-hour period can exceed 30 percent. As part of the Notification of Compliance Status, you must certify that your vent meets the 30 percent opacity limit. If you use a continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in § 63.1572.
7. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM emissions must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off.	The average PM emission rate, measured using EPA Method 5, 5B, or 5F (for a unit without a wet scrubber) or 5 or 5B (for a unit with a wet scrubber) (40 CFR part 60, appendix A–3), over the period of the initial performance test, is no higher than 1.0 g/kg coke burn-off (1.0 lb/1,000 lb) in the catalyst regenerator. The PM emission rate is calculated using Equations 1, 2, and 3 of § 63.1564. If you use a BLD; CO_2, O_2, CO monitor; or continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in § 63.1572.
8. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM emissions must not exceed 0.040 gr/dscf corrected to 0 percent excess air.	The average PM concentration, measured using EPA Method 5, 5B, or 5F (for a unit without a wet scrubber) or Method 5 or 5B (for a unit with a wet scrubber) (40 CFR part 60, appendix A–3), over the period of the initial performance test, is less than or equal to 0.040 gr/dscf corrected to 0 percent excess air. Your performance evaluation shows your PM CEMS meets the applicable requirements in § 63.1572.
9. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM emissions must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off.	The average PM emission rate, measured using EPA Method 5, 5B, or 5F (for a unit without a wet scrubber) or 5 or 5B (for a unit with a wet scrubber) (40 CFR part 60, appendix A–3), over the period of the initial performance test, is no higher than 1.0 g/kg coke burn-off (1.0 lb/1,000 lb) in the catalyst regenerator. The PM emission rate is calculated using Equations 1, 2, and 3 of § 63.1564. If you use a BLD; CO_2, O_2, CO monitor; or continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in § 63.1572.
10. Option 3: Ni lb/hr limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	Nickel (Ni) emissions from your catalyst regenerator vent must not exceed 13,000 mg/hr (0.029 lb/hr).	The average Ni emission rate, measured using Method 29 (40 CFR part 60, appendix A–8) over the period of the initial performance test, is not more than 13,000 mg/hr (0.029 lb/hr). The Ni emission rate is calculated using Equation 5 of § 63.1564; and if you use a BLD; CO_2, O_2, or CO monitor; or continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in § 63.1572.

TABLE 5 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH METAL HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS—Continued

For each new and existing catalytic cracking unit catalyst regenerator vent . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
11. Option 4: Ni per coke burn-off limit not subject to the NSPS for PM.	Ni emissions from your catalyst regenerator vent must not exceed 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator.	The average Ni emission rate, measured using Method 29 (40 CFR part 60, appendix A–8) over the period of the initial performance test, is not more than 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator. The Ni emission rate is calculated using Equation 8 of § 63.1564; and if you use a BLD; CO_2, O_2, or CO monitor; or continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in § 63.1572.

■ 57. Table 6 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1564(c)(1), you shall meet each requirement in the following table that applies to you.

TABLE 6 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH METAL HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	You shall demonstrate continuous compliance by . . .
1. Subject to the NSPS for PM in 40 CFR 60.102 and not electing § 60.100(e).	a. PM emissions must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off, and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. Before August 1, 2017, if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period.	i. Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in § 63.1564 and the hours of operation for each catalyst regenerator.
		ii. Conducting a performance test before August 1, 2017 and thereafter following the testing frequency in § 63.1571(a)(5) as applicable to your unit.
		iii. Collecting the continuous opacity monitoring data for each catalyst regenerator vent according to § 63.1572 and maintaining each 6-minute average at or below 30 percent, except that one 6-minute average during a 1-hour period can exceed 30 percent.
		iv. Before August 1, 2017, if applicable, determining and recording each day the rate of combustion of liquid or solid fossil fuels (liters/hour or kilograms/hour) and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler; if applicable, maintaining the incremental rate of PM at or below 43 g/GJ (0.10 lb/million Btu) of heat input attributable to the solid or liquid fossil fuel.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i), electing to meet the PM per coke burn-off limit.	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off.	Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in § 63.1564 and the hours of operation for each catalyst regenerator; maintaining PM emission rate below 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off; and conducting a performance test once every year.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii), electing to meet the PM per coke burn-off limit.	PM emissions must not exceed 0.5 g/kg coke burn-off (0.5 lb/1000 lb coke burn-off).	Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in § 63.1564 and the hours of operation for each catalyst regenerator; maintaining PM emission rate below 0.5 g/kg (0.5 lb/1,000 lb) of coke burn-off; and conducting a performance test once every year.

TABLE 6 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH METAL HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS—Continued

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	You shall demonstrate continuous compliance by . . .
4. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i), electing to meet the PM concentration limit.	If a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air.	Maintaining PM concentration below 0.040 gr/dscf corrected to 0 percent excess air.
5. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii), electing to meet the PM concentration limit.	If a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air.	Maintaining PM concentration below 0.020 gr/dscf corrected to 0 percent excess air.
6. Option 1a: Elect NSPS subpart J requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	See item 1 of this table	See item 1 of this table.
7. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit and 30% opacity, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off.	See item 2 of this table.
8. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM emissions must not exceed 0.040 gr/dscf corrected to 0 percent excess air.	See item 4 of this table.
9. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off.	Determining and recording each day the average coke burn-off rate and the hours of operation and the hours of operation for each catalyst regenerator by Equation 1 of § 63.1564 (you can use process data to determine the volumetric flow rate); maintaining PM emission rate below 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off; and conducting a performance test before August 1, 2017 and thereafter following the testing frequency in § 63.1571(a)(5) as applicable to your unit.
10. Option 3: Ni lb/hr limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	Ni emissions must not exceed 13,000 mg/hr (0.029 lb/hr).	Maintaining Ni emission rate below 13,000 mg/hr (0.029 lb/hr); and conducting a performance test before August 1, 2017 and thereafter following the testing frequency in § 63.1571(a)(5) as applicable to your unit.
11. Option 4: Ni per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	Ni emissions must not exceed 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator.	Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) and the hours of operation for each catalyst regenerator by Equation 1 of § 63.1564 (you can use process data to determine the volumetric flow rate); and maintaining Ni emission rate below 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator; and conducting a performance test before August 1, 2017 and thereafter following the testing frequency in § 63.1571(a)(5) as applicable to your unit.

■ 58. Table 7 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1564(c)(1), you shall meet each requirement in the following table that applies to you.

TABLE 7 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS for PM in 40 CFR 60.102 and not electing § 60.100(e).	Continuous opacity monitoring system.	The 3-hour average opacity of emissions from your catalyst regenerator vent must not exceed 20 percent.	Collecting the continuous opacity monitoring data for each regenerator vent according to § 63.1572 and maintain each 3-hour rolling average opacity of emissions no higher than 20 percent.

TABLE 7 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1); or 40 CFR 60.102 and elect § 60.100(e), electing to meet the PM per coke burn-off limit.	a. Continuous opacity monitoring system, used for site-specific opacity limit—Cyclone or electrostatic precipitator.	The average opacity must not exceed the opacity established during the performance test.	Collecting the hourly and 3-hr rolling average opacity monitoring data according to § 63.1572; maintaining the 3-hr rolling average opacity at or above the site-specific limit established during the performance test.
	b. Continuous parametric monitoring systems—electrostatic precipitator.	i. The average gas flow rate entering or exiting the control device must not exceed the operating limit established during the performance test.	Collecting the hourly and daily average coke burn-off rate or average gas flow rate monitoring data according to § 63.1572; and maintaining the daily average coke burn-off rate or average gas flow rate at or below the limit established during the performance test.
		ii. The average total power and secondary current to the control device must not fall below the operating limit established during the performance test.	Collecting the hourly and 3-hr rolling average total power and secondary current monitoring data according to § 63.1572; and maintaining the 3-hr rolling average total power and secondary current at or above the limit established during the performance test.
	c. Continuous parametric monitoring systems—wet scrubber.	i. The average liquid-to-gas ratio must not fall below the operating limit established during the performance test.	Collecting the hourly and 3-hr rolling average gas flow rate and scrubber liquid flow rate monitoring data according to § 63.1572; determining and recording the 3-hr liquid-to-gas ratio; and maintaining the 3-hr rolling average liquid-to-gas ratio at or above the limit established during the performance test.
		ii. Except for periods of startup, shutdown and hot standby, the average pressure drop across the scrubber must not fall below the operating limit established during the performance test.	Collecting the hourly and 3-hr rolling average pressure drop monitoring data according to § 63.1572; and except for periods of startup, shutdown and hot standby, maintaining the 3-hr rolling average pressure drop at or above the limit established during the performance test.
	d. BLD—fabric filter	Increases in relative particulate	Collecting and maintaining records of BLD system output; determining the cause of the alarm within 1 hour of the alarm; and alleviating the cause of the alarm within 3 hours by corrective action.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1), electing to meet the PM concentration limit.	PM CEMS	Not applicable	Complying with Table 6 of this subpart, item 4 or 5.
4. Option 1a: Elect NSPS subpart J requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	Continuous opacity monitoring system.	The 3-hour average opacity of emissions from your catalyst regenerator vent must not exceed 20 percent.	Collecting the 3-hr rolling average continuous opacity monitoring system data according to § 63.1572; and maintaining the 3-hr rolling average opacity no higher than 20 percent.
5. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	a. Continuous opacity monitoring system.	The opacity of emissions from your catalyst regenerator vent must not exceed the site-specific opacity operating limit established during the performance test.	Collecting the 3-hr rolling average continuous opacity monitoring system data according to § 63.1572; maintaining the 3-hr rolling average opacity at or below the site-specific limit.

TABLE 7 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
	b. Continuous parametric monitoring systems—electrostatic precipitator.	See item 2.b of this table	See item 2.b of this table.
	c. Continuous parametric monitoring systems—wet scrubber.	See item 2.c of this table	See item 2.c of this table.
	d. BLD—fabric filter	See item 2.d of this table	See item 2.d of this table.
6. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM CEMS	Not applicable	Complying with Table 6 of this subpart, item 4.
7. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	a. Continuous opacity monitoring system.	The opacity of emissions from your catalyst regenerator vent must not exceed the site-specific opacity operating limit established during the performance test.	Collecting the hourly and 3-hr rolling average continuous opacity monitoring system data according to § 63.1572; and maintaining the 3-hr rolling average opacity at or below the site-specific limit established during the performance test. Alternatively, before August 1, 2017, collecting the hourly average continuous opacity monitoring system data according to § 63.1572; and maintaining the hourly average opacity at or below the site-specific limit.
	b. Continuous parameter monitoring systems—electrostatic precipitator.	i. The average coke burn-off rate or average gas flow rate entering or exiting the control device must not exceed the operating limit established during the performance test.	Collecting the hourly and daily average coke burn-off rate or gas flow rate monitoring data according to § 63.1572; and maintaining the daily coke burn-off rate or average gas flow rate at or below the limit established during the performance test.
		ii. The average total power (voltage and current) and secondary current to the control device must not fall below the operating limit established during the performance test.	Collecting the hourly and 3-hr rolling average total power and secondary current monitoring data according to § 63.1572; and maintaining the 3-hr rolling average total power and secondary current at or above the limit established during the performance test. Alternatively, before August 1, 2017, collecting the hourly and daily average voltage and secondary current (or total power input) monitoring data according to § 63.1572; and maintaining the daily average voltage and secondary current (or total power input) at or above the limit established during the performance test.

TABLE 7 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
	c. Continuous parameter monitoring systems—wet scrubber.	i. The average liquid-to-gas ratio must not fall below the operating limit established during the performance test.	Collecting the hourly and 3-hr rolling average gas flow rate and scrubber liquid flow rate monitoring data according to § 63.1572; determining and recording the 3-hr liquid-to-gas ratio; and maintaining the 3-hr rolling average liquid-to-gas ratio at or above the limit established during the performance test. Alternatively, before August 1, 2017, collecting the hourly average gas flow rate and water (or scrubbing liquid) flow rate monitoring data according to § 63.1572[1]; determining and recording the hourly average liquid-to-gas ratio; determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test.
		ii. Except for periods of startup, shutdown and hot standby, the average pressure drop across the scrubber must not fall below the operating limit established during the performance test.	Collecting the hourly and 3-hr rolling average pressure drop monitoring data according to § 63.1572; and except for periods of startup, shutdown and hot standby, maintaining the 3-hr rolling average pressure drop at or above the limit established during the performance test. Alternatively, before August 1, 2017, collecting the hourly and daily average pressure drop monitoring data according to § 63.1572; and maintaining the daily average pressure drop above the limit established during the performance test.
	d. BLD—fabric filter	See item 2.d of this table	See item 2.d of this table.
8. Option 3: Ni lb/hr limit not subject to the NSPS for PM in 40 CFR 60.102.	a. Continuous opacity monitoring system.	i. The daily average Ni operating value must not exceed the site-specific Ni operating limit established during the performance test.	(1) Collecting the hourly average continuous opacity monitoring system data according to § 63.1572; determining and recording equilibrium catalyst Ni concentration at least once a week[2]; collecting the hourly average gas flow rate monitoring data according to § 63.1572[1]; and determining and recording the hourly average Ni operating value using Equation 11 of § 63.1564.

TABLE 7 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
			(2) Determining and recording the 3-hour rolling average Ni operating value and maintaining the 3-hour rolling average Ni operating value below the site-specific Ni operating limit established during the performance test. Alternatively, before August 1, 2017, determining and recording the daily average Ni operating value and maintaining the daily average Ni operating value below the site-specific Ni operating limit established during the performance test.
	b. Continuous parameter monitoring systems—electrostatic precipitator.	i. The average gas flow rate entering or exiting the control device must not exceed the operating limit established during the performance test.	See item 7.b.i of this table.
		ii. The average total power (voltage and current) and secondary current must not fall below the level established in the performance test.	See item 7.b.ii of this table.
		iii. The monthly rolling average of the equilibrium catalyst Ni concentration must not exceed the level established during the performance test.	Determining and recording the equilibrium catalyst Ni concentration at least once a week [2]; determining and recording the monthly rolling average of the equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.
	c. Continuous parameter monitoring systems—wet scrubber.	i. The average liquid-to-gas ratio must not fall below the operating limit established during the performance test..	See item 7.c.i of this table.
		ii. Except for periods of startup, shutdown and hot standby, the average pressure drop must not fall below the operating limit established in the performance test.	See item 7.c.ii of this table.
		iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test.	Determining and recording the equilibrium catalyst Ni concentration at least once a week [2]; determining and recording the monthly rolling average of equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.
	d. BLD—fabric filter	i. Increases in relative particulate	See item 7.d of this table.

TABLE 7 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
		ii. The monthly rolling average of the equilibrium catalyst Ni concentration must not exceed the level established during the performance test.	Determining and recording the equilibrium catalyst Ni concentration at least once a week[2]; determining and recording the monthly rolling average of the equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.
9. Option 4: Ni per coke burn-off limit not subject to the NSPS for PM in 40 CFR 60.102.	a. Continuous opacity monitoring system.	i. The daily average Ni operating value must not exceed the site-specific Ni operating limit established during the performance test.	(1) Collecting the hourly average continuous opacity monitoring system data according to § 63.1572; collecting the hourly average coke burn rate and hourly average gas flow rate monitoring data according to § 63.15721; determining and recording equilibrium catalyst Ni concentration at least once a week[2]; and determining and recording the hourly average Ni operating value using Equation 12 of § 63.1564. (2) Determining and recording the 3-hour rolling average Ni operating value and maintaining the 3-hour rolling average Ni operating value below the site-specific Ni operating limit established during the performance test Alternatively, before August 1, 2017, determining and recording the daily average Ni operating value and maintaining the daily average Ni operating value below the site-specific Ni operating limit established during the performance test.
	b. Continuous parameter monitoring systems—electrostatic precipitator.	i. The average gas flow rate to the control device must not exceed the level established in the performance test.	See item 7.b.i of this table.
		ii. The average voltage and secondary current (or total power input) must not fall below the level established in the performance test.	See item 7.b.ii of this table.
		iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test.	See item 8.b.iii of this table.
	c. Continuous parameter monitoring systems—wet scrubber.	i. The average liquid-to-gas ratio must not fall below the operating limit established during the performance test.	See item 7.c.i of this table.
		ii. Except for periods of startup, shutdown and hot standby, the daily average pressure drop must not fall below the operating limit established in the performance test.	See item 7.c.ii of this table.

TABLE 7 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
		iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test.	See item 8.c.iii of this table.
	d. BLD—fabric filter	i. See item 2.d of this table	See item 2.d of this table.
		ii. The monthly rolling average of the equilibrium catalyst Ni concentration must not exceed the level established during the performance test.	Determining and recording the equilibrium catalyst Ni concentration at least once a week[2]; determining and recording the monthly rolling average of the equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.
10. During periods of startup, shutdown, or hot standby.	Any control device, if elected	The inlet velocity limit to the primary internal cyclones of the catalytic cracking unit catalyst regenerator in § 63.1564(a)(5)(ii).	Meeting the requirements in § 63.1564(c)(5).

[1] If applicable, you can use the alternative in § 63.1573(a)(1) for gas flow rate instead of a continuous parameter monitoring system if you used the alternative method in the initial performance test.

[2] The equilibrium catalyst Ni concentration must be measured by the procedure, Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure) in appendix A to this subpart; or by EPA Method 6010B, Inductively Coupled Plasma-Atomic Emission Spectrometry, EPA Method 6020, Inductively Coupled Plasma-Mass Spectrometry, EPA Method 7520, Nickel Atomic Absorption, Direct Aspiration, or EPA Method 7521, Nickel Atomic Absorption, Direct Aspiration; or by an alternative to EPA Method 6010B, 6020, 7520, or 7521 satisfactory to the Administrator. The EPA Methods 6010B, 6020, 7520, and 7521 are included in ''Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,'' EPA Publication SW–846, Revision 5 (April 1998). The SW–846 and Updates (document number 955–001–00000–1) are available for purchase from the Superintendent of Documents, U.S. Government Publishing Office, Washington, DC 20402, (202) 512–1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487–4650. Copies may be inspected at the EPA Docket Center, William Jefferson Clinton (WJC) West Building (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street NW., Suite 700, Washington, DC. These methods are also available at *http://www.epa.gov/epaoswer/hazwaste/test/main.htm*.

■ 59. Table 8 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1565(a)(1), you shall meet each emission limitation in the following table that applies to you.

TABLE 8 TO SUBPART UUU OF PART 63—ORGANIC HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

For each new and existing catalytic cracking unit . . .	You shall meet the following emission limit for each catalyst regenerator vent . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 or 60.102a(b)(4).	CO emissions from the catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 parts per million volume (ppmv) (dry basis).
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4)	a. CO emissions from the catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis). b. If you use a flare to meet the CO limit, then on and after January 30, 2019, the flare must meet the requirements of § 63.670. Prior to January 30, 2019, the flare must meet the requirements for control devices in § 63.11(b) and visible emissions must not exceed a total of 5 minutes during any 2 consecutive hours, or the flare must meet the requirements of § 63.670.

■ 60. Table 9 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1565(a)(2), you shall meet each operating limit in the following table that applies to you.

TABLE 9 TO SUBPART UUU OF PART 63—OPERATING LIMITS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 or 60.102a(b)(4).	Continuous emission monitoring system.	Not applicable	Not applicable.
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4).	a. Continuous emission monitoring system.	Not applicable	Not applicable.
	b. Continuous parameter monitoring systems.	i. Thermal incinerator	Maintain the daily average combustion zone temperature above the limit established during the performance test; and maintain the daily average oxygen concentration in the vent stream (percent, dry basis) above the limit established during the performance test.
		ii. Boiler or process heater with a design heat input capacity under 44 MW or a boiler or process heater in which all vent streams are not introduced into the flame zone.	Maintain the daily average combustion zone temperature above the limit established in the performance test.
		iii. Flare	On and after January 30, 2019, the flare must meet the requirements of § 63.670. Prior to January 30, 2019, the flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it, or the flare must meet the requirements of § 63.670.
3. During periods of startup, shutdown or hot standby.	Any	Any	Meet the requirements in § 63.1565(a)(5).

■ 61. Table 10 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1565(b)(1), you shall meet each requirement in the following table that applies to you.

TABLE 10 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

For each new or existing catalytic cracking unit . . .	And you use this type of control device for your vent . . .	You shall install, operate, and maintain this type of continuous monitoring system . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 or 60.102a(b)(4).	Not applicable	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent.
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4).	a. Thermal incinerator	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the combustion zone temperature and oxygen content (percent, dry basis) in the incinerator vent stream.
	b. Process heater or boiler with a design heat input capacity under 44 MW or process heater or boiler in which all vent streams are not introduced into the flame zone.	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the combustion zone temperature.

TABLE 10 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new or existing catalytic cracking unit . . .	And you use this type of control device for your vent . . .	You shall install, operate, and maintain this type of continuous monitoring system . . .
	c. Flare	On and after January 30, 2019, the monitoring systems required in §§ 63.670 and 63.671. Prior to January 30, 2019, monitoring device such as a thermocouple, an ultraviolet beam sensor, or infrared sensor to continuously detect the presence of a pilot flame, or the monitoring systems required in §§ 63.670 and 63.671.
	d. No control device	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent.
3. During periods of startup, shutdown or hot standby electing to comply with the operating limit in § 63.1565(a)(5)(ii).	Any	Continuous parameter monitoring system to measure and record the concentration by volume (dry basis) of oxygen from each catalyst regenerator vent.

■ 62. Table 11 to subpart UUU of part 63 is amended by revising the entry for item 3 to read as follows:

* * * * *

TABLE 11 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC CRACKING UNITS NOT SUBJECT TO NEW SOURCE PERFORMANCE STANDARD (NSPS) FOR CARBON MONOXIDE (CO)

For . . .	You must . . .	Using . . .	According to these requirements . . .
*	* *	* *	*
3. Each catalytic cracking unit catalyst regenerator vent if you use continuous parameter monitoring systems.	a. Measure the CO concentration (dry basis) of emissions exiting the control device.	Method 10, 10A, or 10B in appendix A–4 to part 60 of this chapter, as applicable.	
	b. Establish each operating limit in Table 9 of this subpart that applies to you.	Data from the continuous parameter monitoring systems.	
	c. Thermal incinerator combustion zone temperature.	Data from the continuous parameter monitoring systems.	Collect temperature monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average combustion zone temperature from all the readings.
	d. Thermal incinerator: oxygen, content (percent, dry basis) in the incinerator vent stream.	Data from the continuous parameter monitoring systems.	Collect oxygen concentration (percent, dry basis) monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average percent excess oxygen concentration from all the readings.
	e. If you use a process heater or boiler with a design heat input capacity under 44 MW or process heater or boiler in which all vent streams are not introduced into the flame zone, establish operating limit for combustion zone temperature.	Data from the continuous parameter monitoring systems.	Collect the temperature monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average combustion zone temperature from all the readings.

Table 11 to Subpart UUU of Part 63—Requirements for Performance Tests for Organic HAP Emissions From Catalytic Cracking Units Not Subject to New Source Performance Standard (NSPS) for Carbon Monoxide (CO)—Continued

For . . .	You must . . .	Using . . .	According to these requirements . . .
	f. If you use a flare, conduct visible emission observations.	Method 22 (40 CFR part 60, appendix A–7).	On and after January 30, 2019, meet the requirements of § 63.670. Prior to January 30, 2019, maintain a 2-hour observation period; and record the presence of a flame at the pilot light over the full period of the test or meet the requirements of § 63.670.
	g. If you use a flare, determine that the flare meets the requirements for net heating value of the gas being combusted and exit velocity.	40 CFR 63.11(b)(6) through (8)	On and after January 30, 2019, the flare must meet the requirements of § 63.670. Prior to January 30, 2019, the flare must meet the control device requirements in § 63.11(b) or the requirements of § 63.670.

■ 63. Table 12 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1565(b)(4), you shall meet each requirement in the following table that applies to you.

Table 12 to Subpart UUU of Part 63—Initial Compliance With Organic HAP Emission Limits for Catalytic Cracking Units

For each new and existing catalytic cracking unit . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103, 60.100(e), or 60.102a(b)(4).	CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured CO emissions are less than or equal to 500 ppm (dry basis). As part of the Notification of Compliance Status, you must certify that your vent meets the CO limit. You are not required to conduct another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in § 63.1572. You are not required to conduct another performance evaluation to demonstrate initial compliance.
2. Not subject to the NSPS for CO in 40 CFR 60.103 60.102a(b)(4).	a. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	i. If you use a continuous parameter monitoring system, the average CO emissions measured by Method 10 over the period of the initial performance test are less than or equal to 500 ppmv (dry basis).
		ii. If you use a continuous emission monitoring system, the hourly average CO emissions over the 24-hour period for the initial performance test are not more than 500 ppmv (dry basis); and your performance evaluation shows your continuous emission monitoring system meets the applicable requirements in § 63.1572.
	b. If you use a flare, visible emissions must not exceed a total of 5 minutes during any 2 operating hours.	On and after January 30, 2019, the flare meets the requirements of § 63.670. Prior to January 30, 2019, visible emissions, measured by Method 22 during the 2-hour observation period during the initial performance test, are no higher than 5 minutes, or the flare meets the requirements of § 63.670.

■ 64. Table 13 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1565(c)(1), you shall meet each requirement in the following table that applies to you.

TABLE 13 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH ORGANIC HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	If you must . . .	You shall demonstrate continuous compliance by . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103, 60.100(e), or 60.102a(b)(4).	CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	Continuous emission monitoring system.	Collecting the hourly average CO monitoring data according to § 63.1572; and maintaining the hourly average CO concentration at or below 500 ppmv (dry basis).
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4).	a. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	Continuous emission monitoring system.	Same as item 1.
	b. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	Continuous parameter monitoring system.	Maintaining the hourly average CO concentration below 500 ppmv (dry basis).
	c. Visible emissions from a flare must not exceed a total of 5 minutes during any 2-hour period.	Control device-flare	On and after January 30, 2019, meeting the requirements of § 63.670. Prior to January 30, 2019, maintaining visible emissions below a total of 5 minutes during any 2-hour operating period, or meeting the requirements of § 63.670.

■ 65. Table 14 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1565(c)(1), you shall meet each requirement in the following table that applies to you.

TABLE 14 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

For each new existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS for carbon monoxide (CO) in 40 CFR 60.103, 60.100(e), 60.102a(b)(4).	Continuous emission monitoring system.	Not applicable	Complying with Table 13 of this subpart, item 1.
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4).	a. Continuous emission monitoring system.	Not applicable	Complying with Table 13 of this subpart, item 2.a.
	b. Continuous parameter monitoring systems—thermal incinerator.	i. The daily average combustion zone temperature must not fall below the level established during the performance test.	Collecting the hourly and daily average temperature monitoring data according to § 63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test.
		ii. The daily average oxygen concentration in the vent stream (percent, dry basis) must not fall below the level established during the performance test.	Collecting the hourly and daily average oxygen concentration monitoring data according to § 63.1572; and maintaining the daily average oxygen concentration above the limit established during the performance test.
	c. Continuous parameter monitoring systems—boiler or process heater with a design heat input capacity under 44 MW or boiler or process heater in which all vent streams are not introduced into the flame zone.	The daily combustion zone temperature must not fall below the level established in the performance test.	Collecting the average hourly and daily temperature monitoring data according to § 63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test.

TABLE 14 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

For each new existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
	d. Continuous parameter monitoring system—flare.	The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it.	On and after January 30, 2019, meeting the requirements of § 63.670. Prior to January 30, 2019, collecting the flare monitoring data according to § 63.1572 and recording for each 1-hour period whether the monitor was continuously operating and the pilot light was continuously present during each 1-hour period, or meeting the requirements of § 63.670.
3. During periods of startup, shutdown or hot standby electing to comply with the operating limit in § 63.1565(a)(5)(ii).	Any control device	The oxygen concentration limit in § 63.1565(a)(5)(ii).	Collecting the hourly average oxygen concentration monitoring data according to § 63.1572 and maintaining the hourly average oxygen concentration at or above 1 volume percent (dry basis).

■ 66. Table 15 to subpart UUU of part 63 is amended by revising the entry for item 1 to read as follows:

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TABLE 15 TO SUBPART UUU OF PART 63—ORGANIC HAP EMISSION LIMITS FOR CATALYTIC REFORMING UNITS

For each applicable process vent for a new or existing catalytic reforming unit . . .	You shall meet this emission limit during initial catalyst depressuring and catalyst purging operations . . .
1. Option 1	On and after January 30, 2019, vent emissions to a flare that meets the requirements of § 63.670. Prior to January 30, 2019, vent emissions to a flare that meets the requirements for control devices in § 63.11(b) and visible emissions from a flare must not exceed a total of 5 minutes during any 2-hour operating period, or vent emissions to a flare that meets the requirements of § 63.670.
* * * *	* * *

■ 67. Table 16 to subpart UUU of part 63 is amended by revising the entry for item 1 to read as follows:

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TABLE 16 TO SUBPART UUU OF PART 63—OPERATING LIMITS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

For each new or existing catalytic reforming unit . . .	For this type of control device . . .	You shall meet this operating limit during initial catalyst depressuring and purging operations. . .
1. Option 1: Vent to flare	Flare	On and after January 30, 2019, the flare must meet the requirements of § 63.670. Prior to January 30, 2019, the flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it, or the flare must meet the requirements of § 63.670.
* *	* *	* * *

■ 68. Table 17 to subpart UUU of part 63 is amended by revising the entry for item 1 to read as follows:

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TABLE 17 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

For each applicable process vent for a new or existing catalytic reforming unit . . .	If you use this type of control device . . .	You shall install and operate this type of continuous monitoring system . . .
1. Option 1: Vent to a flare	Flare	On and after January 30, 2019, the monitoring systems required in §§ 63.670 and 63.671. Prior to January 30, 2019, monitoring device such as a thermocouple, an ultraviolet beam sensor, or infrared sensor to continuously detect the presence of a pilot flame, or the monitoring systems required in §§ 63.670 and 63.671.

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■ 69. Table 18 to subpart UUU of part 63 is amended by revising the column headings and the entry for item 1 to read as follows:

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TABLE 18 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

For each new or existing catalytic reforming unit . . .	You must . . .	Using . . .	According to these requirements . . .
1. Option 1: Vent to a flare	a. Conduct visible emission observations.	Method 22 (40 CFR part 60, appendix A–7).	On and after January 30, 2019, the flare must meet the requirements of § 63.670. Prior to January 30, 2019, 2-hour observation period. Record the presence of a flame at the pilot light over the full period of the test, or the requirements of § 63.670.
	b. Determine that the flare meets the requirements for net heating value of the gas being combusted and exit velocity.	40 CFR 63.11(b)(6) through (8)	On and after January 30, 2019, the flare must meet the requirements of § 63.670. Prior to January 30, 2019, the flare must meet the control device requirements in § 63.11(b) or the requirements of § 63.670.

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■ 70. Table 19 to subpart UUU of part 63 is amended by revising the entry for item 1 to read as follows:

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TABLE 19 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH ORGANIC HAP EMISSION LIMITS FOR CATALYTIC REFORMING UNITS

For each applicable process vent for a new or existing catalytic reforming unit . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
Option 1	Visible emissions from a flare must not exceed a total of 5 minutes during any 2 consecutive hours.	On and after January 30, 2019, the flare meets the requirements of § 63.670. Prior to January 30, 2019, visible emissions, measured using Method 22 over the 2-hour observation period of the performance test, do not exceed a total of 5 minutes, or the flare meets the requirements of § 63.670.

* * * * * * *

■ 71. Table 20 to subpart UUU of part 63 is amended by revising the entry for item 1 to read as follows:

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TABLE 20 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH ORGANIC HAP EMISSION LIMITS FOR CATALYTIC REFORMING UNITS

For each applicable process vent for a new or existing catalytic reforming unit . . .	For this emission limit . . .	You shall demonstrate continuous compliance during initial catalyst depressuring and catalyst purging operations by . . .
1. Option 1	Vent emissions from your process vent to a flare.	On and after January 30, 2019, meeting the requirements of § 63.670. Prior to January 30, 2019, maintaining visible emissions from a flare below a total of 5 minutes during any 2 consecutive hours, or meeting the requirements of § 63.670.
* * * * * * *		

■ 72. Table 21 to subpart UUU of part 63 is amended by revising the entry for item 1 to read as follows:

* * * * *

TABLE 21 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

For each applicable process vent for a new or existing catalytic reforming unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance during initial catalyst depressuring and purging operations by . . .
1. Option 1	Flare	The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it.	On and after January 30, 2019, meeting the requirements of § 63.670. Prior to January 30, 2019, collecting flare monitoring data according to § 63.1572 and recording for each 1-hour period whether the monitor was continuously operating and the pilot light was continuously present during each 1-hour period, or meeting the requirements of § 63.670.
* * * * * * *			

■ 73. Table 22 to subpart UUU of part 63 is amended by revising the entries for items 2 and 3 to read as follows:

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TABLE 22 TO SUBPART UUU OF PART 63—INORGANIC HAP EMISSION LIMITS FOR CATALYTIC REFORMING UNITS

For . . .	You shall meet this emission limit for each applicable catalytic reforming unit process vent during coke burn-off and catalyst rejuvenation . . .
* * * * * * *	
2. Each existing cyclic or continuous catalytic reforming unit	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.
3. Each new semi-regenerative, cyclic, or continuous catalytic reforming unit.	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.

■ 74. Table 24 to subpart UUU of part 63 is amended by revising the entries for items 2 through 4 and footnote 2 to read as follows:

* * * * *

TABLE 24 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR INORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

If you use this type of control device for your vent . . .	You shall install and operate this type of continuous monitoring system . . .
* * * *	* * *
2. Internal scrubbing system or no control device (*e.g.,* hot regen system) to meet HCl outlet concentration limit.	Colormetric tube sampling system to measure the HCl concentration in the catalyst regenerator exhaust gas during coke burn-off and catalyst rejuvenation. The colormetric tube sampling system must meet the requirements in Table 41 of this subpart.
3. Internal scrubbing system to meet HCl percent reduction standard ...	Continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record the total water (or scrubbing liquid) flow rate entering the internal scrubbing system during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation.[2]
4. Fixed-bed gas-solid adsorption system	Continuous parameter monitoring system to measure and record the temperature of the gas entering or exiting the adsorption system during coke burn-off and catalyst rejuvenation; and colormetric tube sampling system to measure the gaseous HCl concentration in the adsorption system exhaust and at a point within the absorbent bed not to exceed 90 percent of the total length of the absorbent bed during coke burn-off and catalyst rejuvenation. The colormetric tube sampling system must meet the requirements in Table 41 of this subpart.
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[2] If applicable, you can use the alternative in § 63.1573(c)(1) instead of a continuous parameter monitoring system for pH of the water (or scrubbing liquid) or the alternative in § 63.1573(c)(2) instead of a continuous parameter monitoring system for alkalinity of the water (or scrubbing liquid).

* * * * *

■ 75. Table 25 to subpart UUU of part 63 is amended by revising the entries for items 2.a and 4.a and footnote 1 to read as follows:

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TABLE 25 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR INORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

For each new and existing catalytic reforming unit using . . .	You shall . . .	Using . . .	According to these requirements . . .
* *	* *	*	* *
2. Wet scrubber	a. Establish operating limit for pH level or alkalinity.	i. Data from continuous parameter monitoring systems.	Measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting scrubber every 15 minutes during the entire period of the performance test. Determine and record the minimum hourly average pH or alkalinity level from the recorded values.
		ii. Alternative pH procedure in § 63.1573(b)(1).	Measure and record the pH of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation using pH strips at least three times during each test run. Determine and record the average pH level for each test run. Determine and record the minimum test run average pH level.

TABLE 25 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR INORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS—Continued

For each new and existing catalytic reforming unit using . . .	You shall . . .	Using . . .	According to these requirements . . .
		iii. Alternative alkalinity method in § 63.1573(c)(2).	Measure and record the alkalinity of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation using discrete titration at least three times during each test run. Determine and record the average alkalinity level for each test run. Determine and record the minimum test run average alkalinity level.
* * *	* * *	*	* *
4. Internal scrubbing system meeting HCl percent reduction standard.	a. Establish operating limit for pH level or alkalinity.	i. Data from continuous parameter monitoring system.	Measure and record the pH alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system every 15 minutes during the entire period of the performance test. Determine and record the minimum hourly average pH or alkalinity level from the recorded values.
		ii. Alternative pH method in § 63.1573(c)(1).	Measure and in record pH of the water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation using pH strips at least three times during each test run. Determine and record the average pH level for each test run. Determine and record the minimum test run average pH level.
		iii. Alternative alkalinity method in § 63.1573(c)(2).	Measure and record the alkalinity water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation using discrete titration at least three times during each test run. Determine and record the average alkalinity level for each test run. Determine and record the minimum test run average alkalinity level.
* * *	* * *	*	* *

[1] The EPA Methods 5050, 9056, 9212 and 9253 are included in ''Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,'' EPA Publication SW–846, Revision 5 (April 1998). The SW–846 and Updates (document number 955–001–00000–1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512–1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487–4650. Copies may be inspected at the EPA Docket Center, William Jefferson Clinton (WJC) West Building (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street NW., Suite 700, Washington, DC. These methods are also available at *http://www.epa.gov/epaoswer/hazwaste/test/main.htm*.

■ 76. Table 28 to subpart UUU of part 63 is amended by revising the entry for item 5 and footnotes 1 and 3 to read as follows:

* * * * *

TABLE 28 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR INORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

For each new and existing catalytic reforming unit using this type of control device or system . . .	For this operating limit . . .	You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by . . .

TABLE 28 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR INORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS—Continued

For each new and existing catalytic reforming unit using this type of control device or system . . .	For this operating limit . . .	You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by . . .
* *	* * *	* *
5. Moving-bed gas-solid adsorption system (*e.g.,* ChlorsorbTM System).	a. The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test.	Collecting the hourly and daily average temperature monitoring data according to § 63.1572; and maintaining the daily average temperature below the operating limit established during the performance test.
	b. The weekly average chloride level on the sorbent entering the adsorption system must not exceed the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb™ System).	Collecting samples of the sorbent exiting the adsorption system three times per week (on non-consecutive days); and analyzing the samples for total chloride[3]; and determining and recording the weekly average chloride concentration; and maintaining the chloride concentration below the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb™ System).
	c. The weekly average chloride level on the sorbent exiting the adsorption system must not exceed the design or manufacturer's recommended limit (1.8 weight percent for the Chlorsorb™ System).	Collecting samples of the sorbent exiting the adsorption system three times per week (on non-consecutive days); and analyzing the samples for total chloride concentration; and determining and recording the weekly average chloride concentration; and maintaining the chloride concentration below the design or manufacturer's recommended limit (1.8 weight percent Chlorsorb™ System).

[1] If applicable, you can use either alternative in § 63.1573(c) instead of a continuous parameter monitoring system for pH or alkalinity if you used the alternative method in the initial performance test.

* * * * * * *

[3] The total chloride concentration of the sorbent material must be measured by the procedure, ''Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure)'' in appendix A to this subpart; or by using EPA Method 5050, Bomb Preparation Method for Solid Waste, combined either with EPA Method 9056, Determination of Inorganic Anions by Ion Chromatography, or with EPA Method 9253, Chloride (Titrimetric, Silver Nitrate); or by using EPA Method 9212, Potentiometric Determination of Chloride in Aqueous Samples with Ion-Selective Electrode, and using the soil extraction procedures listed within the method. The EPA Methods 5050, 9056, 9212 and 9253 are included in ''Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,'' EPA Publication SW–846, Revision 5 (April 1998). The SW–846 and Updates (document number 955–001–00000–1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512–1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487–4650. Copies may be inspected at the EPA Docket Center, William Jefferson Clinton (WJC) West Building, (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street NW., Suite 700, Washington, DC. These methods are also available at *http://www.epa.gov/epaoswer/hazwaste/test/main.htm*.

■ 77. Table 29 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1568(a)(1), you shall meet each emission limitation in the following table that applies to you.

TABLE 29 TO SUBPART UUU OF PART 63—HAP EMISSION LIMITS FOR SULFUR RECOVERY UNITS

For . . .	You shall meet this emission limit for each process vent . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 long tons per day (LTD) and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 250 ppmv (dry basis) of sulfur dioxide (SO_2) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation control system or if you use a reduction control system followed by incineration.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation control system or if you use a reduction control system followed by incineration.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	300 ppmv of total reduced sulfur (TRS) compounds, expressed as an equivalent SO_2 concentration (dry basis) at zero percent oxygen.

■ 78. Table 30 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1568(a)(2), you shall meet each operating limit in the following table that applies to you.

TABLE 30 TO SUBPART UUU OF PART 63—OPERATING LIMITS FOR HAP EMISSIONS FROM SULFUR RECOVERY UNITS

For . . .	If use this type of control device . . .	You shall meet this operating limit . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	Not applicable	Not applicable.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	Not applicable	Not applicable.
3. Option 2: TRS limit, if using continuous emissions monitoring systems. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	Not applicable	Not applicable.
4. Option 2: TRS limit, if using continuous parameter monitoring systems. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	Thermal incinerator	Maintain the daily average combustion zone temperature above the limit established during the performance test; and maintain the daily average oxygen concentration in the vent stream (percent, dry basis) above the limit established during the performance test.
5. Startup or shutdown option 1: Electing to comply with § 63.1568(a)(4)(ii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown.	Flare	On and after January 30, 2019, meet the applicable requirements of § 63.670. Prior to January 30, 2019, meet the applicable requirements of either § 63.11(b) or § 63.670.
6. Startup or shutdown option 2: Electing to comply with § 63.1568(a)(4)(iii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during startup or shutdown events.	Thermal incinerator or thermal oxidizer	Maintain the hourly average combustion zone temperature at or above 1,200 degrees Fahrenheit and maintain the hourly average oxygen concentration in the exhaust gas stream at or above 2 volume percent (dry basis).

■ 79. Table 31 to subpart UUU is revised to read as follows:

As stated in § 63.1568(b)(1), you shall meet each requirement in the following table that applies to you.

TABLE 31 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR HAP EMISSIONS FROM SULFUR RECOVERY UNITS

For . . .	For this limit . . .	You shall install and operate this continuous monitoring system . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air if you use an oxidation or reduction control system followed by incineration.	Continuous emission monitoring system to measure and record the hourly average concentration of SO_2 (dry basis) at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air.

TABLE 31 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR HAP EMISSIONS FROM SULFUR RECOVERY UNITS—Continued

For . . .	For this limit . . .	You shall install and operate this continuous monitoring system . . .
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air if you use a reduction control system without incineration.	Continuous emission monitoring system to measure and record the hourly average concentration of reduced sulfur and oxygen (O_2) emissions. Calculate the reduced sulfur emissions as SO_2 (dry basis) at zero percent excess air. *Exception:* You can use an instrument having an air or SO_2 dilution and oxidation system to convert the reduced sulfur to SO_2 for continuously monitoring and recording the concentration (dry basis) at zero percent excess air of the resultant SO_2 instead of the reduced sulfur monitor. The monitor must include an oxygen monitor for correcting the data for excess oxygen.
	c. If you use Equation 1 of 40 CFR 60.102a(f)(1)(i) to set your emission limit.	i. Complete either item 1.a or item 1.b; and ii. Either a continuous emission monitoring system to measure and record the O_2 concentration for the inlet air/oxygen supplied to the system or a continuous parameter monitoring system to measure and record the volumetric gas flow rate of ambient air and purchased oxygen-enriched gas.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air if you use an oxidation or reduction control system followed by incineration.	Continuous emission monitoring system to measure and record the hourly average concentration of SO_2 (dry basis), at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air if you use a reduction control system without incineration.	Continuous emission monitoring system to measure and record the hourly average concentration of reduced sulfur and O_2 emissions for each exhaust stack. Calculate the reduced sulfur emissions as SO_2 (dry basis), at zero percent excess air. *Exception:* You can use an instrument having an air or O_2 dilution and oxidation system to convert the reduced sulfur to SO_2 for continuously monitoring and recording the concentration (dry basis) at zero percent excess air of the resultant SO_2 instead of the reduced sulfur monitor. The monitor must include an oxygen monitor for correcting the data for excess oxygen.
	c. If you use Equation 1 of 40 CFR 60.102a(f)(1)(i) to set your emission limit.	i. Complete either item 2.a or item 2.b; and ii. Either a continuous emission monitoring system to measure and record the O_2 concentration for the inlet air/oxygen supplied to the system, or a continuous parameter monitoring system to measure and record the volumetric gas flow rate of ambient air and purchased oxygen-enriched gas.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 300 ppmv of total reduced sulfur (TRS) compounds, expressed as an equivalent SO_2 concentration (dry basis) at zero percent oxygen.	i. Continuous emission monitoring system to measure and record the hourly average concentration of TRS for each exhaust stack; this monitor must include an oxygen monitor for correcting the data for excess oxygen; or ii. Continuous parameter monitoring systems to measure and record the combustion zone temperature of each thermal incinerator and the oxygen content (percent, dry basis) in the vent stream of the incinerator.

TABLE 31 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR HAP EMISSIONS FROM SULFUR RECOVERY UNITS—Continued

For . . .	For this limit . . .	You shall install and operate this continuous monitoring system . . .
4. Startup or shutdown option 1: electing to comply with § 63.1568(a)(4)(ii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown.	Any	On and after January 30, 2019, monitoring systems as specified in §§ 63.670 and 63.671. Prior to January 30, 2019, either continuous parameter monitoring systems following the requirements in § 63.11 (to detect the presence of a flame; to measure and record the net heating value of the gas being combusted; and to measure and record the volumetric flow of the gas being combusted) or monitoring systems as specified in §§ 63.670 and 63.671.
5. Startup or shutdown option 2: electing to comply with § 63.1568(a)(4)(iii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown.	Any	Continuous parameter monitoring systems to measure and record the firebox temperature of each thermal incinerator or oxidizer and the oxygen content (percent, dry basis) in the exhaust vent from the incinerator or oxidizer.

■ 80. Table 32 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1568(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

TABLE 32 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR HAP EMISSIONS FROM SULFUR RECOVERY UNITS NOT SUBJECT TO THE NEW SOURCE PERFORMANCE STANDARDS FOR SULFUR OXIDES

For . . .	You must . . .	Using . . .	According to these requirements . . .
1. Option 1: Elect NSPS. Each new and existing sulfur recovery unit.	a. Measure SO_2 concentration (for an oxidation or reduction system followed by incineration) or measure the concentration of reduced sulfur (or SO_2 if you use an instrument to convert the reduced sulfur to SO_2) for a reduction control system without incineration.	Data from continuous emission monitoring system.	Collect SO_2 monitoring data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period.
	b. Measure O_2 concentration for the inlet air/oxygen supplied to the system, if using Equation 1 of 40 CFR 60.102a(f)1)(i) to set your emission limit. You may use either an O_2 CEMS method in item 1.b.i of this table or the flow monitor in item 1.b.ii of this table.	i. Data from continuous emission monitoring system; or	Collect O_2 monitoring data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period; and average over the 24-hour period for input to Equation 1 of 40 CFR 60.102a(f)(1)(i).
		ii. Data from flow monitor for ambient air and purchased oxygen-enriched gas.	Collect gas flow rate monitoring data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from 4 or more data points equally spaced over each 1-hour period; calculate the hourly O_2 percent using Equation 10 of 40 CFR 60.106a(a)(6)(iv); and average over the 24-hour period for input to Equation 1 of 40 CFR 60.102a(f)(1)(i).
2. Option 2: TRS limit, using CEMS. Each new and existing sulfur recovery unit.	Measure the concentration of reduced sulfur (or SO_2 if you use an instrument to convert the reduced sulfur to SO_2).	Data from continuous emission monitoring system.	Collect TRS data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period.

TABLE 32 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR HAP EMISSIONS FROM SULFUR RECOVERY UNITS NOT SUBJECT TO THE NEW SOURCE PERFORMANCE STANDARDS FOR SULFUR OXIDES—Continued

For . . .	You must . . .	Using . . .	According to these requirements . . .
3. Option 2: TRS limit, if using continuous parameter monitoring systems. Each new and existing sulfur recovery unit.	a. Select sampling port's location and the number of traverse ports.	Method 1 or 1A in Appendix A–1 to part 60 of this chapter.	Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.
	b. Determine velocity and volumetric flow rate.	Method 2, 2A, 2C, 2D, or 2F in appendix A–1 to part 60 of this chapter, or Method 2G in appendix A–2 to part 60 of this chapter, as applicable.	
	c. Conduct gas molecular weight analysis; obtain the oxygen concentration needed to correct the emission rate for excess air.	Method 3, 3A, or 3B in appendix A–2 to part 60 of this chapter, as applicable.	Take the samples simultaneously with reduced sulfur or moisture samples.
	d. Measure moisture content of the stack gas.	Method 4 in appendix A–3 to part 60 of this chapter.	Make your sampling time for each Method 4 sample equal to that for 4 Method 15 samples.
	e. Measure the concentration of TRS.	Method 15 or 15A in appendix A–5 to part 60 of this chapter, as applicable.	If the cross-sectional area of the duct is less than 5 square meters (m^2) or 54 square feet, you must use the centroid of the cross section as the sampling point. If the cross-sectional area is 5 m^2 or more and the centroid is more than 1 meter (m) from the wall, your sampling point may be at a point no closer to the walls than 1 m or 39 inches. Your sampling rate must be at least 3 liters per minute or 0.10 cubic feet per minute to ensure minimum residence time for the sample inside the sample lines.
	f. Calculate the SO_2 equivalent for each run after correcting for moisture and oxygen.	The arithmetic average of the SO_2 equivalent for each sample during the run.	
	g. Correct the reduced sulfur samples to zero percent excess air.	Equation 1 of § 63.1568	
	h. Establish each operating limit in Table 30 of this subpart that applies to you.	Data from the continuous parameter monitoring system.	
	i. Measure thermal incinerator: combustion zone temperature.	Data from the continuous parameter monitoring system.	Collect temperature monitoring data every 15 minutes during the entire period of the performance test; and determine and record the minimum hourly average temperature from all the readings.
	j. Measure thermal incinerator: oxygen concentration (percent, dry basis) in the vent stream.	Data from the continuous parameter monitoring system.	Collect oxygen concentration (percent, dry basis) data every 15 minutes during the entire period of the performance test; and determine and record the minimum hourly average percent excess oxygen concentration.

■ 81. Table 33 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1568(b)(5), you shall meet each requirement in the following table that applies to you.

TABLE 33 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH HAP EMISSION LIMITS FOR SULFUR RECOVERY UNITS

For . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Subject to NSPS: Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 250 ppmv (dry basis) SO_2 at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation or reduction control system followed by incineration.	You have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12-hour rolling average concentration of SO_2 emissions measured by the continuous emission monitoring system is less than or equal to 250 ppmv (dry basis) at zero percent excess air, or the concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i). As part of the Notification of Compliance Status, you must certify that your vent meets the SO_2 limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in § 63.1572. You are not required to do another performance evaluation to demonstrate initial compliance.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration.	You have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12-hour rolling average concentration of reduced sulfur compounds measured by your continuous emission monitoring system is less than or equal to 300 ppmv, calculated as ppmv SO_2 (dry basis) at zero percent excess air, or the concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i). As part of the Notification of Compliance Status, you must certify that your vent meets the SO_2 limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in § 63.1572. You are not required to do another performance evaluation to demonstrate initial compliance.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation or reduction control system followed by incineration.	Each 12-hour rolling average concentration of SO_2 emissions measured by the continuous emission monitoring system during the initial performance test is less than or equal to 250 ppmv (dry basis) at zero percent excess air, or the concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i); and your performance evaluation shows the monitoring system meets the applicable requirements in § 63.1572.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration.	Each 12-hour rolling average concentration of reduced sulfur compounds measured by the continuous emission monitoring system during the initial performance test is less than or equal to 300 ppmv, calculated as ppmv SO_2 (dry basis) at zero percent excess air, or the concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i); and your performance evaluation shows the continuous emission monitoring system meets the applicable requirements in § 63.1572.

TABLE 33 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH HAP EMISSION LIMITS FOR SULFUR RECOVERY UNITS—Continued

For . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	300 ppmv of TRS compounds expressed as an equivalent SO_2 concentration (dry basis) at zero percent oxygen.	If you use continuous parameter monitoring systems, the average concentration of TRS emissions measured using Method 15 during the initial performance test is less than or equal to 300 ppmv expressed as equivalent SO_2 concentration (dry basis) at zero percent oxygen. If you use a continuous emission monitoring system, each 12-hour rolling average concentration of TRS emissions measured by the continuous emission monitoring system during the initial performance test is less than or equal to 300 ppmv expressed as an equivalent SO_2 (dry basis) at zero percent oxygen; and your performance evaluation shows the continuous emission monitoring system meets the applicable requirements in § 63.1572.

■ 82. Table 34 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1568(c)(1), you shall meet each requirement in the following table that applies to you.

TABLE 34 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH HAP EMISSION LIMITS FOR SULFUR RECOVERY UNITS

For . . .	For this emission limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation or reduction control system followed by incineration.	Collecting the hourly average SO_2 monitoring data (dry basis, percent excess air) and, if using Equation 1 of 40 CFR 60.102a(f)(1)(i), collecting the hourly O_2 concentration or flow monitoring data according to § 63.1572; determining and recording each 12-hour rolling average concentration of SO_2; maintaining each 12-hour rolling average concentration of SO_2 at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of SO_2 greater than the applicable emission limitation in the semiannual compliance report required by § 63.1575.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration.	Collecting the hourly average reduced sulfur (and air or O_2 dilution and oxidation) monitoring data and, if using Equation 1 of 40 CFR 60.102a(f)(1)(i), collecting the hourly O_2 concentration or flow monitoring data according to § 63.1572; determining and recording each 12-hour rolling average concentration of reduced sulfur; maintaining each 12-hour rolling average concentration of reduced sulfur at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of reduced sulfur greater than the applicable emission limitation in the semiannual compliance report required by § 63.1575.

TABLE 34 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH HAP EMISSION LIMITS FOR SULFUR RECOVERY UNITS—Continued

For . . .	For this emission limit . . .	You shall demonstrate continuous compliance by . . .
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation or reduction control system followed by incineration.	Collecting the hourly average SO_2 data (dry basis, percent excess air) and, if using Equation 1 of 40 CFR 60.102a(f)(1)(i), collecting the hourly O_2 concentration or flow monitoring data according to § 63.1572; determining and recording each 12-hour rolling average concentration of SO_2; maintaining each 12-hour rolling average concentration of SO_2 at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of SO_2 greater than the applicable emission limitation in the semiannual compliance report required by § 63.1575.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration.	Collecting the hourly average reduced sulfur (and air or O_2 dilution and oxidation) monitoring data and, if using Equation 1 of 40 CFR 60.102a(f)(1)(i), collecting the hourly O_2 concentration or flow monitoring data according to § 63.1572; determining and recording each 12-hour rolling average concentration of reduced sulfur; maintaining each 12-hour rolling average concentration of reduced sulfur at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of reduced sulfur greater than the applicable emission limitation in the semiannual compliance report required by § 63.1575.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	300 ppmv of TRS compounds, expressed as an SO_2 concentration (dry basis) at zero percent oxygen or reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air.	i. If you use continuous parameter monitoring systems, collecting the hourly average TRS monitoring data according to § 63.1572 and maintaining each 12-hour average concentration of TRS at or below the applicable emission limitation; or ii. If you use a continuous emission monitoring system, collecting the hourly average TRS monitoring data according to § 63.1572, determining and recording each 12-hour rolling average concentration of TRS; maintaining each 12-hour rolling average concentration of TRS at or below the applicable emission limitation; and reporting any 12-hour rolling average TRS concentration greater than the applicable emission limitation in the semiannual compliance report required by § 63.1575.

■ 83. Table 35 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1568(c)(1), you shall meet each requirement in the following table that applies to you.

TABLE 35 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR HAP EMISSIONS FROM SULFUR RECOVERY UNITS

For . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	Not applicable	Meeting the requirements of Table 34 of this subpart.

TABLE 35 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR HAP EMISSIONS FROM SULFUR RECOVERY UNITS—Continued

For . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	Not applicable	Meeting the requirements of Table 34 of this subpart.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. Maintain the daily average combustion zone temperature above the level established during the performance test.	Collecting the hourly and daily average temperature monitoring data according to § 63.1572; and maintaining the daily average combustion zone temperature at or above the limit established during the performance test
	b. The daily average oxygen concentration in the vent stream (percent, dry basis) must not fall below the level established during the performance test..	Collecting the hourly and daily average O_2 monitoring data according to § 63.1572; and maintaining the average O_2 concentration above the level established during the performance test.
4. Startup or shutdown option 1: Electing to comply with § 63.1568(a)(4)(ii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown.	Using a flare meeting the requirements in § 63.11(b) or § 63.670.	On and after January 30, 2019, complying with the applicable requirements of § 63.670. Prior to January 30, 2019, complying with the applicable requirements of either § 63.11(b) or § 63.670.
5. Startup or shutdown option 2: Electing to comply with § 63.1568(a)(4)(iii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown.	a. Minimum hourly average temperature of 1,200 degrees Fahrenheit.	Collecting continuous (at least once every 15 minutes) and hourly average temperature monitoring data according to § 63.1572; and maintaining the daily average firebox temperature at or above 1,200 degrees Fahrenheit.
	b. Minimum hourly average outlet oxygen concentration of 2 volume percent (dry basis).	Collecting continuous (at least once every 15 minutes) and hourly average O_2 monitoring data according to § 63.1572; and maintaining the average O_2 concentration at or above 2 volume percent (dry basis).

■ 84. Table 40 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1572(a)(1) and (b)(1), you shall meet each requirement in the following table that applies to you.

TABLE 40 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR INSTALLATION, OPERATION, AND MAINTENANCE OF CONTINUOUS OPACITY MONITORING SYSTEMS AND CONTINUOUS EMISSION MONITORING SYSTEMS

This type of continuous opacity or emission monitoring system . . .	Must meet these requirements . . .
1. Continuous opacity monitoring system	Performance specification 1 (40 CFR part 60, appendix B).
2. PM CEMS; this monitor must include an O_2 monitor for correcting the data for excess air.	The requirements in 40 CFR 60.105a(d).
3. CO continuous emission monitoring system	Performance specification 4 (40 CFR part 60, appendix B); span value of 1,000 ppm; and procedure 1 (40 CFR part 60, appendix F) except relative accuracy test audits are required annually instead of quarterly.
4. CO continuous emission monitoring system used to demonstrate emissions average under 50 ppm (dry basis).	Performance specification 4 (40 CFR part 60, appendix B); and span value of 100 ppm.
5. SO_2 continuous emission monitoring system for sulfur recovery unit with oxidation control system or reduction control system; this monitor must include an O_2 monitor for correcting the data for excess air.	Performance specification 2 (40 CFR part 60, appendix B); span value of 500 ppm SO_2, or if using Equation 1 of 40 CFR 60.102a(f)(1)(i), span value of two times the limit at the highest O_2 concentration; use Methods 6 or 6C (40 CFR part 60, appendix A–4) for certifying the SO_2 monitor and Methods 3A or 3B (40 CFR part 60, appendix A–2) for certifying the O_2 monitor; and procedure 1 (40 CFR part 60, appendix F) except relative accuracy test audits are required annually instead of quarterly.

TABLE 40 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR INSTALLATION, OPERATION, AND MAINTENANCE OF CONTINUOUS OPACITY MONITORING SYSTEMS AND CONTINUOUS EMISSION MONITORING SYSTEMS—Continued

This type of continuous opacity or emission monitoring system . . .	Must meet these requirements . . .
6. Reduced sulfur and O_2 continuous emission monitoring system for sulfur recovery unit with reduction control system not followed by incineration; this monitor must include an O_2 monitor for correcting the data for excess air unless exempted.	Performance specification 5 (40 CFR part 60, appendix B), except calibration drift specification is 2.5 percent of the span value instead of 5 percent; span value is 450 ppm reduced sulfur, or if using Equation 1 of 40 CFR 60.102a(f)(1)(i), span value of two times the limit at the highest O_2 concentration; use Methods 15 or 15A (40 CFR part 60, appendix A–5) for certifying the reduced sulfur monitor and Methods 3A or 3B (40 CFR part 60, appendix A–2) for certifying the O_2 monitor; if Method 3A or 3B yields O_2 concentrations below 0.25 percent during the performance evaluation, the O_2 concentration can be assumed to be zero and the O_2 monitor is not required; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.
7. Instrument with an air or O_2 dilution and oxidation system to convert reduced sulfur to SO_2 for continuously monitoring the concentration of SO_2 instead of reduced sulfur monitor and O_2 monitor.	Performance specification 5 (40 CFR part 60, appendix B); span value of 375 ppm SO_2 or if using Equation 1 of 40 CFR 60.102a(f)(1)(i), span value of two times the limit at the highest O_2 concentration; use Methods 15 or 15A (40 CFR part 60, appendix A–5) for certifying the reduced sulfur monitor and 3A or 3B (40 CFR part 60, appendix A–2) for certifying the O_2 monitor; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.
8. TRS continuous emission monitoring system for sulfur recovery unit; this monitor must include an O_2 monitor for correcting the data for excess air.	Performance specification 5 (40 CFR part 60, appendix B).
9. O_2 monitor for oxygen concentration	If necessary due to interferences, locate the oxygen sensor prior to the introduction of any outside gas stream; performance specification 3 (40 CFR part 60, appendix B; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.

■ 85. Table 41 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1572(c)(1), you shall meet each requirement in the following table that applies to you.

TABLE 41 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR INSTALLATION, OPERATION, AND MAINTENANCE OF CONTINUOUS PARAMETER MONITORING SYSTEMS

If you use . . .	You shall . . .
1. pH strips	Use pH strips with an accuracy of ±10 percent.
2. pH meter	Locate the pH sensor in a position that provides a representative measurement of pH; ensure the sample is properly mixed and representative of the fluid to be measured. Use a pH sensor with an accuracy of at least ±0.2 pH units. Check the pH meter's calibration on at least one point at least once daily; check the pH meter's calibration on at least two points at least once quarterly; at least monthly, inspect all components for integrity and all electrical components for continuity; record the results of each calibration check and inspection.
3. Colormetric tube sampling system.	Use a colormetric tube sampling system with a printed numerical scale in ppmv, a standard measurement range of 1 to 10 ppmv (or 1 to 30 ppmv if applicable), and a standard deviation for measured values of no more than ±15 percent. System must include a gas detection pump and hot air probe if needed for the measurement range.
4. CO_2, O_2, and CO monitors for coke burn-off rate.	a. Locate the concentration sensor so that it provides a representative measurement of the content of the exit gas stream; ensure the sample is properly mixed and representative of the gas to be measured. Use a sensor with an accuracy of at least ±1 percent of the range of the sensor or to a nominal gas concentration of ±0.5 percent, whichever is greater. Use a monitor that is able to measure concentration on a dry basis or is able to correct for moisture content and record on a dry basis. Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the sensor reading exceeds the manufacturer's specified maximum operating range or install a new sensor; at least quarterly, inspect all components for integrity and all electrical connections for continuity; record the results of each calibration and inspection. b. As an alternative, the requirements in 40 CFR 60.105a(b)(2) may be used.
5. BLD	Follow the requirements in 40 CFR 60.105a(c).
6. Voltage, secondary current, or total power input sensors.	Use meters with an accuracy of at least ±5 percent over the operating range.

TABLE 41 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR INSTALLATION, OPERATION, AND MAINTENANCE OF CONTINUOUS PARAMETER MONITORING SYSTEMS—Continued

If you use . . .	You shall . . .
	Each time that the unit is not operating, confirm that the meters read zero. Conduct a calibration check at least annually; conduct calibration checks following any period of more than 24 hours throughout which the meter reading exceeds the manufacturer's specified maximum operating range; at least monthly, inspect all components of the continuous parameter monitoring system for integrity and all electrical connections for continuity; record the results of each calibration check and inspection.
7. Pressure/Pressure drop[1] sensors.	Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.
	Use a gauge with an accuracy of at least ±5 percent over the normal operating range or 0.12 kilopascals (0.5 inches of water column), whichever is greater.
	Review pressure sensor readings at least once a week for straightline (unchanging) pressure and perform corrective action to ensure proper pressure sensor operation if blockage is indicated; using an instrument recommended by the sensor's manufacturer, check gauge calibration and transducer calibration annually; conduct calibration checks following any period of more than 24 hours throughout which the pressure exceeded the manufacturer's specified maximum rated pressure or install a new pressure sensor; at least quarterly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage, unless the CPMS has a redundant pressure sensor; record the results of each calibration check and inspection.
8. Air flow rate, gas flow rate, or total water (or scrubbing liquid) flow rate sensors.	Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances. If you elect to comply with Option 3 (Ni lb/hr) or Option 4 (Ni lb/1,000 lb of coke burn-off) for the HAP metal emission limitations in § 63.1564, install the continuous parameter monitoring system for gas flow rate as close as practical to the continuous opacity monitoring system; and if you don't use a continuous opacity monitoring system, install the continuous parameter monitoring system for gas flow rate as close as practical to the control device.
	Use a flow rate sensor with an accuracy of at least ±5 percent over the normal range of flow measured, or 1.9 liter per minute (0.5 gallons per minute), whichever is greater, for liquid flow.
	Use a flow rate sensor with an accuracy of at least ±5 percent over the normal range of flow measured, or 280 liters per minute (10 cubic feet per minute), whichever is greater, for gas flow.
	Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor; at least quarterly, inspect all components for leakage, unless the CPMS has a redundant flow sensor; record the results of each calibration check and inspection.
9. Temperature sensors.	Locate the temperature sensor in the combustion zone, or in the ductwork immediately downstream of the combustion zone before any substantial heat exchange occurs or in the ductwork immediately downstream of the regenerator; locate the temperature sensor in a position that provides a representative temperature; shield the temperature sensor system from electromagnetic interference and chemical contaminants.
	Use a temperature sensor with an accuracy of at least ±1 percent over the normal range of temperature measured, expressed in degrees Celsius (C), or 2.8 degrees C, whichever is greater.
	Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the temperature exceeded the manufacturer's specified maximum rated temperature or install a new temperature sensor; at least quarterly, inspect all components for integrity and all electrical connections for continuity, oxidation, and galvanic corrosion, unless the CPMS has a redundant temperature sensor; record the results of each calibration check and inspection.
10. Oxygen content sensors [2].	Locate the oxygen sensor so that it provides a representative measurement of the oxygen content of the exit gas stream; ensure the sample is properly mixed and representative of the gas to be measured.
	Use an oxygen sensor with an accuracy of at least ±1 percent of the range of the sensor or to a nominal gas concentration of ±0.5 percent, whichever is greater.
	Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the sensor reading exceeds the manufacturer's specified maximum operating range or install a new oxygen sensor; at least quarterly, inspect all components for integrity and all electrical connections for continuity; record the results of each calibration and inspection.

[1] Not applicable to non-venturi wet scrubbers of the jet-ejector design.

[2] This does not replace the requirements for oxygen monitors that are required to use continuous emissions monitoring systems. The requirements in this table apply to oxygen sensors that are continuous parameter monitors, such as those that monitor combustion zone oxygen concentration and regenerator exit oxygen concentration.

■ 86. Table 43 to subpart UUU is revised to read as follows:

As stated in § 63.1575(a), you shall meet each requirement in the following table that applies to you.

TABLE 43 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR REPORTS

You must submit . . .	The report must contain . . .	You shall submit the report . . .
1. A compliance report	If there are no deviations from any emission limitation or work practice standard that applies to you, a statement that there were no deviations from the standards during the reporting period and that no continuous opacity monitoring system or continuous emission monitoring system was inoperative, inactive, out-of-control, repaired, or adjusted; if you have a deviation from any emission limitation or work practice standard during the reporting period, the report must contain the information in § 63.1575(c) through (e).	Semiannually according to the requirements in § 63.1575(b).
2. Performance test and CEMS performance evaluation data.	On and after January 30, 2019, the information specified in § 63.1575(k)(1).	Within 60 days after the date of completing each test according to the requirements in § 63.1575(k).

■ 87. Table 44 to subpart UUU of part 63 is revised to read as follows:

As stated in § 63.1577, you shall meet each requirement in the following table that applies to you.

TABLE 44 TO SUBPART UUU OF PART 63—APPLICABILITY OF NESHAP GENERAL PROVISIONS TO SUBPART UUU

Citation	Subject	Applies to subpart UUU	Explanation
§ 63.1(a)(1)–(4)	General Applicability	Yes	
§ 63.1(a)(5)	[Reserved]	Not applicable	
§ 63.1(a)(6)		Yes	Except the correct mail drop (MD) number is C404–04.
§ 63.1(a)(7)–(9)	[Reserved]	Not applicable	
§ 63.1(a)(10)–(12)		Yes	Except that this subpart specifies calendar or operating day.
§ 63.1(b)(1)	Initial Applicability Determination for this part.	Yes	
§ 63.1(b)(2)	[Reserved]	Not applicable	
§ 63.1(b)(3)		Yes	
§ 63.1(c)(1)	Applicability of this part after a Relevant Standard has been set under this part.	Yes	
§ 63.1(c)(2)		No	Area sources are not subject to this subpart.
§ 63.1(c)(3)–(4)	[Reserved]	Not applicable	
§ 63.1(c)(5)		Yes	
§ 63.1(d)	[Reserved]	Not applicable	
§ 63.1(e)	Applicability of Permit Program	Yes	
§ 63.2	Definitions	Yes	§ 63.1579 specifies that if the same term is defined in subparts A and UUU of this part, it shall have the meaning given in this subpart.
§ 63.3	Units and Abbreviations	Yes	
§ 63.4(a)(1)–(2)	Prohibited Activities	Yes	
§ 63.4(a)(3)–(5)	[Reserved]	Not applicable	
§ 63.4(b)–(c)	Circumvention and Fragmentation	Yes	
§ 63.5(a)	Construction and Reconstruction	Yes	
§ 63.5(b)(1)		Yes	
§ 63.5(b)(2)	[Reserved]	Not applicable	
§ 63.5(b)(3)–(4)		Yes	In § 63.5(b)(4), replace the reference to § 63.9(b) with § 63.9(b)(4) and (5).
§ 63.5(b)(5)	[Reserved]	Not applicable	
§ 63.5(b)(6)		Yes	
§ 63.5(c)	[Reserved]	Not applicable	
§ 63.5(d)(1)(i)	Application for Approval of Construction or Reconstruction—General Application Requirements.	Yes	Except this subpart specifies the application is submitted as soon as practicable before startup but not later than 90 days after the promulgation date if construction or reconstruction had commenced and initial startup had not occurred before promulgation.

TABLE 44 TO SUBPART UUU OF PART 63—APPLICABILITY OF NESHAP GENERAL PROVISIONS TO SUBPART UUU—Continued

Citation	Subject	Applies to subpart UUU	Explanation
§ 63.5(d)(1)(ii)		Yes	Except that emission estimates specified in § 63.5(d)(1)(ii)(H) are not required, and § 63.5(d)(1)(ii)(G) and (I) are Reserved and do not apply.
§ 63.5(d)(1)(iii)		No	This subpart specifies submission of notification of compliance status.
§ 63.5(d)(2)		Yes	
§ 63.5(d)(3)		Yes	
§ 63.5(d)(4)		Yes	
§ 63.5(e)	Approval of Construction or Reconstruction.	Yes	
§ 63.5(f)(1)	Approval of Construction or Reconstruction Based on State Review.	Yes	
§ 63.5(f)(2)		Yes	Except that the cross-reference to § 63.9(b)(2) does not apply.
§ 63.6(a)	Compliance with Standards and Maintenance—Applicability.	Yes	
§ 63.6(b)(1)–(4)	Compliance Dates for New and Reconstructed Sources.	Yes	
§ 63.6(b)(5)		Yes	Except that this subpart specifies different compliance dates for sources.
§ 63.6(b)(6)	[Reserved]	Not applicable	
§ 63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major.	Yes	
§ 63.6(c)(1)–(2)	Compliance Dates for Existing Sources.	Yes	Except that this subpart specifies different compliance dates for sources subject to Tier II gasoline sulfur control requirements.
§ 63.6(c)(3)–(4)	[Reserved]	Not applicable	
§ 63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major.	Yes	
§ 63.6(d)	[Reserved]	Not applicable	
§ 63.6(e)(1)(i)	General Duty to Minimize Emissions	No	See § 63.1570(c) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to Correct Malfunctions as Soon as Possible.	No	
§ 63.6(e)(1)(iii)	Compliance with Standards and Maintenance Requirements.	Yes	
§ 63.6(e)(2)	[Reserved]	Not Applicable	
§ 63.6(e)(3)(i)	Startup, Shutdown, and Malfunction Plan Requirements.	No	
§ 63.6(e)(3)(ii)	[Reserved]	Not applicable	
§ 63.6(e)(3)(iii)–(ix)		No	
§ 63.6(f)(1)	SSM Exemption	No	
§ 63.6(f)(2)(i)–(iii)(C)	Compliance with Standards and Maintenance Requirements.	Yes	
§ 63.6(f)(2)(iii)(D)		Yes	
§ 63.6(f)(2)(iv)–(v)		Yes	
§ 63.6(f)(3)		Yes	Except the cross-references to § 63.6(f)(1) and (e)(1)(i) are changed to § 63.1570(c).
§ 63.6(g)	Alternative Standard	Yes	
§ 63.6(h)(1)	SSM Exemption for Opacity/VE Standards.	No	
§ 63.6(h)(2)(i)	Determining Compliance with Opacity/VE Standards.	No	This subpart specifies methods.
§ 63.6(h)(2)(ii)	[Reserved]	Not applicable	
§ 63.6(h)(2)(iii)		Yes	
§ 63.6(h)(3)	[Reserved]	Not applicable	
§ 63.6(h)(4)	Notification of Opacity/VE Observation Date.	Yes	Applies to Method 22 (40 CFR part 60, appendix A–7) tests.
§ 63.6(h)(5)	Conducting Opacity/VE Observations	No	
§ 63.6(h)(6)	Records of Conditions During Opacity/VE Observations.	Yes	Applies to Method 22 (40 CFR part 60, appendix A–7) observations.
§ 63.6(h)(7)(i)	Report COM Monitoring Data from Performance Test.	Yes	
§ 63.6(h)(7)(ii)	Using COM Instead of Method 9	No	

TABLE 44 TO SUBPART UUU OF PART 63—APPLICABILITY OF NESHAP GENERAL PROVISIONS TO SUBPART UUU—Continued

Citation	Subject	Applies to subpart UUU	Explanation
§ 63.6(h)(7)(iii)	Averaging Time for COM during Performance Test.	Yes	
§ 63.6(h)(7)(iv)	COM Requirements	Yes	
§ 63.6(h)(7)(v)	COMS Results and Visual Observations.	Yes	
§ 63.6(h)(8)	Determining Compliance with Opacity/VE Standards.	Yes	
§ 63.6(h)(9)	Adjusted Opacity Standard	Yes	
§ 63.6(i)(1)–(14)	Extension of Compliance	Yes	Extension of compliance under § 63.6(i)(4) not applicable to a facility that installs catalytic cracking feed hydrotreating and receives an extended compliance date under § 63.1563(c).
§ 63.6(i)(15)	[Reserved]	Not applicable	
§ 63.6(i)(16)		Yes	
§ 63.6(j)	Presidential Compliance Exemption	Yes	
§ 63.7(a)(1)	Performance Test Requirements Applicability.	Yes	Except that this subpart specifies the applicable test and demonstration procedures.
§ 63.7(a)(2)	Performance Test Dates	Yes	Except test results must be submitted in the Notification of Compliance Status report due 150 days after the compliance date.
§ 63.7(a)(3)	Section 114 Authority	Yes	
§ 63.7(a)(4)	Force Majeure	Yes	
§ 63.7(b)	Notifications	Yes	Except that this subpart specifies notification at least 30 days prior to the scheduled test date rather than 60 days.
§ 63.7(c)	Quality Assurance Program/Site-Specific Test Plan.	Yes	Except that when this subpart specifies to use 40 CFR part 60, appendix F, out of control periods are to be defined as specified in part 60, appendix F.
§ 63.7(d)	Performance Test Facilities	Yes	
§ 63.7(e)(1)	Performance Testing	No	See § 63.1571(b)(1).
§ 63.7(e)(2)–(4)	Conduct of Tests	Yes	
§ 63.7(f)	Alternative Test Method	Yes	
§ 63.7(g)	Data Analysis, Recordkeeping, Reporting.	Yes	Except performance test reports must be submitted with notification of compliance status due 150 days after the compliance date, and § 63.7(g)(2) is reserved and does not apply.
§ 63.7(h)	Waiver of Tests	Yes	
§ 63.8(a)(1)	Monitoring Requirements-Applicability	Yes	
§ 63.8(a)(2)	Performance Specifications	Yes	
§ 63.8(a)(3)	[Reserved]	Not applicable	
§ 63.8(a)(4)	Monitoring with Flares	Yes	Except that for a flare complying with § 63.670, the cross-reference to § 63.11 in this paragraph does not include § 63.11(b).
§ 63.8(b)(1)	Conduct of Monitoring	Yes	
§ 63.8(b)(2)–(3)	Multiple Effluents and Multiple Monitoring Systems.	Yes	This subpart specifies the required monitoring locations.
§ 63.8(c)(1)	Monitoring System Operation and Maintenance.	Yes	
§ 63.8(c)(1)(i)	General Duty to Minimize Emissions and CMS Operation.	No	See § 63.1570(c).
§ 63.8(c)(1)(ii)	Keep Necessary Parts for CMS	Yes	
§ 63.8(c)(1)(iii)	Requirement to Develop SSM Plan for CMS.	No	

TABLE 44 TO SUBPART UUU OF PART 63—APPLICABILITY OF NESHAP GENERAL PROVISIONS TO SUBPART UUU—Continued

Citation	Subject	Applies to subpart UUU	Explanation
§ 63.8(c)(2)–(3)	Monitoring System Installation	Yes	Except that this subpart specifies that for continuous parameter monitoring systems, operational status verification includes completion of manufacturer written specifications or installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment will monitor accurately.
§ 63.8(c)(4)	Continuous Monitoring System Requirements.	Yes	
§ 63.8(c)(5)	COMS Minimum Procedures	Yes	
§ 63.8(c)(6)	CMS Requirements	Yes	
§ 63.8(c)(7)–(8)	CMS Requirements	Yes	
§ 63.8(d)(1)–(2)	Quality Control Program for CMS	Yes	
§ 63.8(d)(3)	Written Procedures for CMS	No	
§ 63.8(e)	CMS Performance Evaluation	Yes	Except that results are to be submitted as part of the Notification Compliance Status due 150 days after the compliance date.
§ 63.8(f)(1)–(5)	Alternative Monitoring Methods	Yes	Except that this subpart specifies procedures for requesting alternative monitoring systems and alternative parameters.
§ 63.8(f)(6)	Alternative to Relative Accuracy Test	Yes	Applicable to continuous emission monitoring systems if performance specification requires a relative accuracy test audit.
§ 63.8(g)(1)–(4)	Reduction of Monitoring Data	Yes	Applies to continuous opacity monitoring system or continuous emission monitoring system.
§ 63.8(g)(5)	Data Reduction	No	This subpart specifies requirements.
§ 63.9(a)	Notification Requirements—Applicability.	Yes	Duplicate Notification of Compliance Status report to the Regional Administrator may be required.
§ 63.9(b)(1)–(2)	Initial Notifications	Yes	Except that notification of construction or reconstruction is to be submitted as soon as practicable before startup but no later than 30 days after the effective date if construction or reconstruction had commenced but startup had not occurred before the effective date.
§ 63.9(b)(3)	[Reserved]	Not applicable	
§ 63.9(b)(4)–(5)	Initial Notification Information	Yes	Except § 63.9(b)(4)(ii)–(iv), which are reserved and do not apply.
§ 63.9(c)	Request for Extension of Compliance	Yes	
§ 63.9(d)	New Source Notification for Special Compliance Requirements.	Yes	
§ 63.9(e)	Notification of Performance Test	Yes	Except that notification is required at least 30 days before test.
§ 63.9(f)	Notification of VE/Opacity Test	Yes	
§ 63.9(g)	Additional Notification Requirements for Sources with Continuous Monitoring Systems.	Yes	
§ 63.9(h)	Notification of Compliance Status	Yes	Except that this subpart specifies the notification is due no later than 150 days after compliance date, and except that the reference to § 63.5(d)(1)(ii)(H) in § 63.9(h)(5) does not apply.
§ 63.9(i)	Adjustment of Deadlines	Yes	
§ 63.9(j)	Change in Previous Information	Yes	
63.10(a)	Recordkeeping and Reporting Applicability.	Yes	
§ 63.10(b)(1)	General Recordkeeping Requirements.	Yes	

TABLE 44 TO SUBPART UUU OF PART 63—APPLICABILITY OF NESHAP GENERAL PROVISIONS TO SUBPART UUU—Continued

Citation	Subject	Applies to subpart UUU	Explanation
§ 63.10(b)(2)(i)	Recordkeeping of Occurrence and Duration of Startups and Shutdowns.	No	
§ 63.10(b)(2)(ii)	Recordkeeping of Malfunctions	No	See § 63.1576(a)(2) for recordkeeping of (1) date, time and duration; (2) listing of affected source or equipment, and an estimate of the volume of each regulated pollutant emitted over the standard; and (3) actions taken to minimize emissions and correct the failure.
§ 63.10(b)(2)(iii)	Maintenance Records	Yes	
§ 63.10(b)(2)(iv)–(v)	Actions Taken to Minimize Emissions During SSM.	No	
§ 63.10(b)(2)(vi)	Recordkeeping for CMS Malfunctions	Yes	
§ 63.10(b)(2)(vii)–(xiv)	Other CMS Requirements	Yes	
§ 63.10(b)(3)	Recordkeeping for Applicability Determinations..	Yes	
§ 63.10(c)(1)–(6)	Additional Records for Continuous Monitoring Systems.	Yes	Except § 63.10(c)(2)–(4), which are Reserved and do not apply.
§ 63.10(c)(7)–(8)	Additional Recordkeeping Requirements for CMS—Identifying Exceedances and Excess Emissions.	Yes	
§ 63.10(c)(9)	[Reserved]	Not applicable	
§ 63.10(c)(10)	Recording Nature and Cause of Malfunctions.	No	See § 63.1576(a)(2) for malfunctions recordkeeping requirements.
§ 63.10(c)(11)	Recording Corrective Actions	No	See § 63.1576(a)(2) for malfunctions recordkeeping requirements.
§ 63.10(c)(12)–(14)	Additional CMS Recordkeeping Requirements.	Yes	
§ 63.10(c)(15)	Use of SSM Plan	No	
§ 63.10(d)(1)	General Reporting Requirements	Yes	
§ 63.10(d)(2)	Performance Test Results	No	This subpart requires performance test results to be reported as part of the Notification of Compliance Status due 150 days after the compliance date.
§ 63.10(d)(3)	Opacity or VE Observations	Yes	
§ 63.10(d)(4)	Progress Reports	Yes	
§ 63.10(d)(5)	SSM Reports	No	See § 63.1575(d) for CPMS malfunction reporting and § 63.1575(e) for COMS and CEMS malfunction reporting.
§ 63.10(e)(1)–(2)	Additional CMS Reports	Yes	Except that reports of performance evaluations must be submitted in Notification of Compliance Status.
§ 63.10(e)(3)	Excess Emissions/CMS Performance Reports.	No	This subpart specifies the applicable requirements.
§ 63.10(e)(4)	COMS Data Reports	Yes	
§ 63.10(f)	Recordkeeping/Reporting Waiver	Yes	
§ 63.11(a)	Control Device and Work Practice Requirements Applicability.	Yes	
§ 63.11(b)	Flares	Yes	Except that flares complying with § 63.670 are not subject to the requirements of § 63.11(b).
§ 63.11(c)–(e)	Alternative Work Practice for Monitoring Equipment for Leaks.	Yes	
§ 63.12	State Authority and Delegations	Yes	
§ 63.13	Addresses	Yes	
§ 63.14	Incorporation by Reference	Yes	
§ 63.15	Availability of Information and Confidentiality.	Yes	
§ 63.16	Performance Track Provisions	Yes	

■ 88. Appendix A to subpart UUU of part 63 is amended by revising the first sentence of section 2.1 and section 7.1.3 to read as follows:

Appendix A to Subpart UUU of Part 63—Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure)

* * * * *

2.1 A representative sample of catalyst particles is collected, prepared, and analyzed for analyte concentration using either energy or wavelength dispersive X-ray fluorescent (XRF) spectrometry instrumental analyzers. * * *

* * * * *

7.1.3 Low-Range Calibration Standard. Concentration equivalent to 1 to 20 percent of the span. The concentration of the low-range calibration standard should be selected so that it is less than either one-fourth of the applicable concentration limit or of the lowest concentration anticipated in the catalyst samples.

* * * * *

■ 89. Appendix A to part 63 is amended by adding Method 325A and Method 325B in numerical order to read as follows:

Appendix A to Part 63—Test Methods Pollutant Measurement Methods From Various Waste Media

* * * * *

Method 325A—Volatile Organic Compounds from Fugitive and Area Sources:

Sampler Deployment and VOC Sample Collection

1.0 Scope and Application

1.1 This method describes collection of volatile organic compounds (VOCs) at or inside a facility property boundary or from fugitive and area emission sources using passive (diffusive) tube samplers (PS). The concentration of airborne VOCs at or near these potential fugitive- or area-emission sources may be determined using this method in combination with Method 325B. Companion Method 325B (Sampler Preparation and Analysis) describes preparation of sampling tubes, shipment and storage of exposed sampling tubes, and analysis of sampling tubes collected using either this passive sampling procedure or alternative active (pumped) sampling methods.

1.2 This method may be used to determine the average concentration of the select VOCs using the corresponding uptake rates listed in Method 325B, Table 12.1. Additional compounds or alternative sorbents must be evaluated as described in Addendum A of Method 325B or by one of the following national/international standard methods: ISO 16017–2:2003(E), ASTM D6196–03 (Reapproved 2009), or BS EN 14662–4:2005 (all incorporated by reference—see § 63.14), or reported in the peer-reviewed open literature.

1.3 Methods 325A and 325B are valid for the measurement of benzene. Supporting literature (References 1–8) indicates that benzene can be measured by flame ionization detection or mass spectrometry over a concentration range of approximately 0.5 micrograms per cubic meter ($\mu g/m^3$) to at least 500 $\mu g/m^3$ when industry standard (3.5 inch long × 0.25 inch outside diameter (o.d.) × 5 mm inner diameter (i.d.)) inert-coated stainless steel sorbent tubes packed with Carbograph™ 1 TD, Carbopack™ B, or Carbopack™ X or equivalent are used and when samples are accumulated over a period of 14 days.

1.4 This method may be applied to screening average airborne VOC concentrations at facility property boundaries or monitoring perimeters over an extended period of time using multiple sampling periods (*e.g.*, 26 × 14-day sampling periods). The duration of each sampling period is normally 14 days.

1.5 This method requires the collection of local meteorological data (wind speed and direction, temperature, and barometric pressure). Although local meteorology is a component of this method, non-regulatory applications of this method may use regional meteorological data. Such applications risk that the results may not identify the precise source of the emissions.

2.0 Summary of the Method

2.1 Principle of the Method

The diffusive passive sampler collects VOC from air for a measured time period at a rate that is proportional to the concentration of vapor in the air at that location.

2.1.1 This method describes the deployment of prepared passive samplers, including determination of the number of passive samplers needed for each survey and placement of samplers along or inside the facility property boundary depending on the size and shape of the site or linear length of the boundary.

2.1.2 The rate of sampling is specific to each compound and depends on the diffusion constants of that VOC and the sampler dimensions/characteristics as determined by prior calibration in a standard atmosphere (Reference 1).

2.1.3 The gaseous VOC target compounds migrate through a constant diffusion barrier (*e.g.*, an air gap of fixed dimensions) at the sampling end of the diffusion sampling tube and adsorb onto the sorbent.

2.1.4 Heat and a flow of inert carrier gas are then used to extract (desorb) the retained VOCs back from the sampling end of the tube and transport/transfer them to a gas chromatograph (GC) equipped with a chromatographic column to separate the VOCs and a detector to determine the quantity of target VOCs.

2.1.5 Gaseous or liquid calibration standards loaded onto the sampling ends of clean sorbent tubes must be used to calibrate the analytical equipment.

2.1.6 This method requires the use of field blanks to ensure sample integrity associated with shipment, collection, and storage of the passive samples. It also requires the use of field duplicates to validate the sampling process.

2.1.7 At the end of each sampling period, the passive samples are collected, sealed, and shipped to a laboratory for analysis of target VOCs by thermal desorption gas chromatography, as described in Method 325B.

2.2 Application of Diffusive Sampling

2.2.1 This method requires deployment of passive sampling tubes on a monitoring perimeter encompassing all known emission sources at a facility and collection of local meteorological data. It may be used to determine average concentration of VOC at a facility's "fenceline" using time integrated passive sampling (Reference 2).

2.2.2 Collecting samples and meteorological data at progressively higher frequencies may be employed to resolve shorter term concentration fluctuations and wind conditions that could introduce interfering emissions from other sources.

2.2.3 This passive sampling method provides a low cost approach to screening of fugitive or area emissions compared to active sampling methods that are based on pumped sorbent tubes or time weighted average canister sampling.

2.2.3.1 Additional passive sampling tubes may be deployed at different distances from the facility property boundary or from the geometric center of the fugitive emission source.

2.2.3.2 Additional meteorological measurements may also be collected as needed to perform preliminary gradient-based assessment of the extent of the pollution plume at ground level and the effect of "background" sources contributing to airborne VOC concentrations at the location.

2.2.4 Time-resolved concentration measurements coupled with time-resolved meteorological monitoring may be used to generate data needed for source apportionment procedures and mass flux calculations.

3.0 Definitions

(See also Section 3.0 of Method 325B.)

3.1 *Fenceline* means the property boundary of a facility or internal monitoring perimeter established in accordance with the requirements in Section 8.2 of this method.

3.2 *Passive sampler (PS)* means a specific type of sorbent tube (defined in this method) that has a fixed dimension air (diffusion) gap at the sampling end and is sealed at the other end.

3.3 *Passive sampling* refers to the activity of quantitatively collecting VOC on sorbent tubes using the process of diffusion.

3.4 PS_i is the annual average for all PS concentration results from location *i*.

3.5 PS_{i3} is the set of annual average concentration results for PS_i and two sorbent tubes nearest to the PS location *i*.

3.6 PS_{ip} is the concentration from the sorbent tube at location *i* for the test period or episode p.

3.7 *Sampling period* is the length of time each passive sampler is exposed during field monitoring. The sampling period for this method is 14 days.

3.8 *Sorbent tube* (Also referred to as tube, PS tube, adsorbent tube, and sampling tube) is an inert coated stainless steel tube. Standard PS tube dimensions for this method are 3.5-inch (89 mm) long × 0.25-inch (6.4 mm) o.d. with an i.d. of 5 mm, a cross-sectional area of 19.6 mm^2 and an air gap of 15 mm. The central portion of the tube is packed with solid adsorbent material contained between 2 × 100-mesh stainless steel gauzes and terminated with a diffusion cap at the sampling end of the tube. These axial passive samplers are installed under a protective hood during field deployment.

Note: Glass and glass- (or fused silica-) lined stainless steel sorbent tubes (typically 4 mm i.d.) are also available in various lengths to suit different makes of thermal desorption equipment, but these are rarely used for passive sampling because it is more difficult to adequately define the diffusive air gap in glass or glass-line tubing. Such tubes are not recommended for this method.

4.0 Sampling Interferences

4.1 General Interferences

Passive tube samplers should be sited at a distance beyond the influence of possible obstructions such as trees, walls, or buildings at the monitoring site. Complex topography and physical site obstructions, such as bodies of water, hills, buildings, and other structures that may prevent access to a planned PS location must be taken into consideration. You must document and report siting interference with the results of this method.

4.2 Background Interference

Nearby or upwind sources of target emissions outside the facility being tested can contribute to background concentrations. Moreover, because passive samplers measure continuously, changes in wind direction can cause variation in the level of background concentrations from interfering sources during the monitoring period. This is why local meteorological information, particularly wind direction and speed, is required to be collected throughout the monitoring period. Interfering sources can include neighboring industrial facilities, transportation facilities, fueling operations, combustion sources, short-term transient sources, residential sources, and nearby highways or roads. As PS data are evaluated, the location of potential interferences with respect to PS locations and local wind conditions should be considered, especially when high PS concentration values are observed.

4.3 Tube Handling

You must protect the PS tubes from gross external contamination during field sampling. Analytical thermal desorption equipment used to analyze PS tubes must desorb organic compounds from the interior of PS tubes and exclude contamination from external sampler surfaces in the analytical/sample flow path. If the analytical equipment does not comply with this requirement, you must wear clean, white, cotton or powder-free nitrile gloves to handle sampling tubes to prevent contamination of the external sampler surfaces. Sampling tubes must be capped with two-piece, brass, 0.25 inch, long-term storage caps fitted with combined polytetrafluoroethylene ferrules (see Section 6.1 and Method 325B) to prevent ingress of airborne contaminants outside the sampling period. When not being used for field monitoring, the capped tubes must be stored in a clean, air-tight, shipping container to prevent the collection of VOCs (see Section 6.4.2 of Method 325B).

4.4 Local Weather Conditions and Airborne Particulates

Although air speeds are a constraint for many forms of passive samplers, axial tube PS devices have such a slow inherent uptake rate that they are largely immune to these effects (References 4,5). Passive samplers must nevertheless be deployed under non-emitting weatherproof hoods to moderate the effect of local weather conditions such as solar heating and rain. The cover must not impede the ingress of ambient air. Sampling tubes should also be orientated vertically and pointing downwards, to minimize accumulation of particulates.

4.5 Temperature

The normal working range for field sampling for sorbent packing is 0–40 °C (References 6,7). Note that most published passive uptake rate data for sorbent tubes is quoted at 20 °C. Note also that, as a rough guide, an increase in temperature of 10 °C will reduce the collection capacity for a given analyte on a given sorbent packing by a factor of 2, but the uptake rate will not change significantly (Reference 4).

5.0 Safety

This method does not purport to include all safety issues or procedures needed when deploying or collecting passive sampling tubes. Precautions typical of field air sampling projects are required. Tripping, falling, electrical, and weather safety considerations must all be included in plans to deploy and collect passive sampling tubes.

6.0 Sampling Equipment and Supplies, and Pre-Deployment Planning

This section describes the equipment and supplies needed to deploy passive sampling monitoring equipment at a facility property boundary. Details of the passive sampling tubes themselves and equipment required for subsequent analysis are described in Method 325B.

6.1 Passive Sampling Tubes

The industry standard PS tubes used in this method must meet the specific configuration and preparation requirements described in Section 3.0 of this method and Section 6.1 of Method 325B.

Note: The use of PS tubes packed with various sorbent materials for monitoring a wide variety of organic compounds in ambient air has been documented in the literature (References 4–10). Other sorbents may be used in standard passive sampling tubes for monitoring additional target compound(s) once their uptake rate and performance has been demonstrated following procedures in Addendum A to Method 325B. Guidance on sorbent selection can also be obtained from relevant national and international standard methods such as ASTM D6196–03 (Reapproved 2009) (Reference 14) and ISO 16017–2:2003(E) (Reference 13) (both incorporated by reference—see § 63.14).

6.2 Passive or Diffusive Sampling Cap

One diffusive sampling cap is required per PS tube. The cap fits onto the sampling end of the tube during air monitoring. The other end of the tube remains sealed with the long-term storage cap. Each diffusive sampling cap is fitted with a stainless steel gauze, which defines the outer limit of the diffusion air gap.

6.3 Sorbent Tube Protection Cover

A simple weatherproof hood, suitable for protecting passive sampling tubes from the worst of the weather (see Section 4.4) consists of an inverted cone/funnel constructed of an inert, non-outgassing material that fits over the diffusive tube, with the open (sampling) end of the tube projecting just below the cone opening. An example is shown in Figure 6.1 (Adapted from Reference 13).

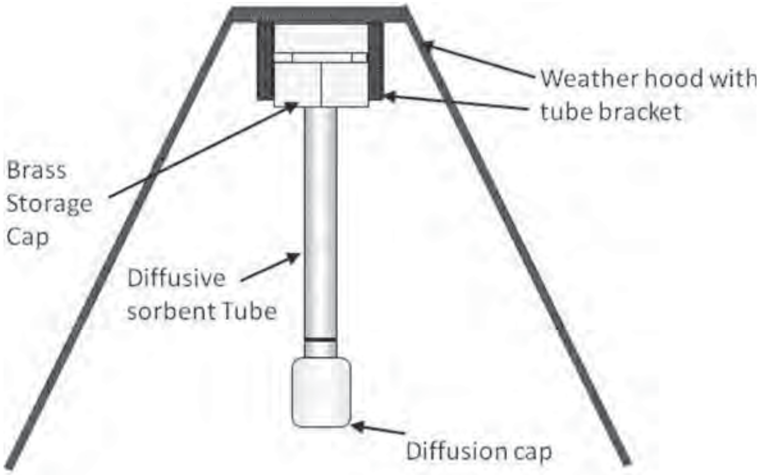

Figure 6.1. PS Tube with Weather Protector

6.4 Thermal Desorption Apparatus

If the analytical thermal desorber that will subsequently be used to analyze the passive sampling tubes does not meet the requirement to exclude outer surface contaminants from the sample flow path (see Section 6.6 of Method 325B), then clean, white, cotton or powder-free nitrile gloves must be used for handling the passive sampling tubes during field deployment.

6.5 Sorbent Selection

Sorbent tube configurations, sorbents or other VOC not listed in this method must be evaluated according to Method 325B, Addendum A or ISO 16017–2:2003(E) (Reference 13) (incorporated by reference—see § 63.14). The supporting evaluation and verification data described in Method 325B, Addendum A for configurations or compounds different from the ones described in this method must meet the performance requirements of Method 325A/B and must be submitted with the test plan for your measurement program.

7.0 Reagents and Standards

No reagents or standards are needed for the field deployment and collection of passive sampling tubes. Specifications for sorbents, gas and liquid phase standards, preloaded standard tubes, and carrier gases are covered in Section 7 of Method 325B.

8.0 Sample Deployment, Recovery, and Storage

Pre-deployment and planning steps are required before field deployment of passive sampling tubes. These activities include but are not limited to conducting a site visit, determining suitable and required monitoring locations, and determining the monitoring frequency to be used.

8.1 Conducting the Site Visit

8.1.1 Determine the size and shape of the facility footprint in order to determine the required number of monitoring locations.

8.1.2 Identify obstacles or obstructions (buildings, roads, fences), hills and other terrain issues (*e.g.,* bodies of water or swamp land) that could interfere with air parcel flow to the sampler or that prevent reasonable access to the location. You may use the general guidance in Section 4.1 of this method during the site visit to identify sampling locations. You must evaluate the placement of each passive sampler to determine if the conditions in this section are met.

8.1.3 Identify to the extent possible and record potential off-site source interferences (*e.g.,* neighboring industrial facilities, transportation facilities, fueling operations, combustion sources, short-term transient sources, residential sources, nearby highways).

8.1.4 Identify the closest available meteorological station. Identify potential locations for one or more on-site or near-site meteorological station(s) following the guidance in EPA–454/B–08–002 (Reference 11) (incorporated by reference—see § 63.14).

8.2 Determining Sampling Locations (References 2, 3)

8.2.1 The number and placement of the passive samplers depends on the size, the shape of the facility footprint or the linear distance around the facility, and the proximity of emission sources near the property boundaries. Aerial photographs or site maps may be used to determine the size (acreage) and shape of the facility or the length of the monitoring perimeter. Place passive samplers on an internal monitoring perimeter on or inside the facility boundary encompassing all emission sources at the facility at different angles circling the geometric center of the facility or at different distances based on the monitoring perimeter length of the facility.

Note: In some instances, permanent air monitoring stations may already be located in close proximity to the facility. These stations may be operated and maintained by the site, or local or state regulatory agencies. If access to the station is possible, a PS may be deployed adjacent to other air monitoring instrumentation. A comparison of the pollutant concentrations measured with the PS to concentrations measured by site instrumentation may be used as an optional data quality indicator to assess the accuracy of PS results.

8.2.1.1 The monitoring perimeter may be located between the property boundary and any potential emission source near the property boundary, as long as the distance from the source to the monitoring perimeter is at least 50 meters (162 feet). If a potential emissions source is within 50 meters (162 feet) of the property boundary, the property boundary shall be used as the monitoring perimeter near that source.

8.2.1.2 Samplers need only be placed around the monitoring perimeter and not along internal roads or other right of ways that may bisect the facility.

8.2.1.3 Extra samplers must be placed near known sources of VOCs if the potential emission source is within 50 meters (162 feet) of the boundary and the source location is between two monitors. Measure the distance (x) between the two monitors and place another monitor halfway between (x/2) the two monitors. For example, in Figure 8.1, the facility added three additional monitors (*i.e.,* light shaded sampler locations) and in Figure 8.2, the facility added two additional monitors to provide sufficient coverage of all area sources.

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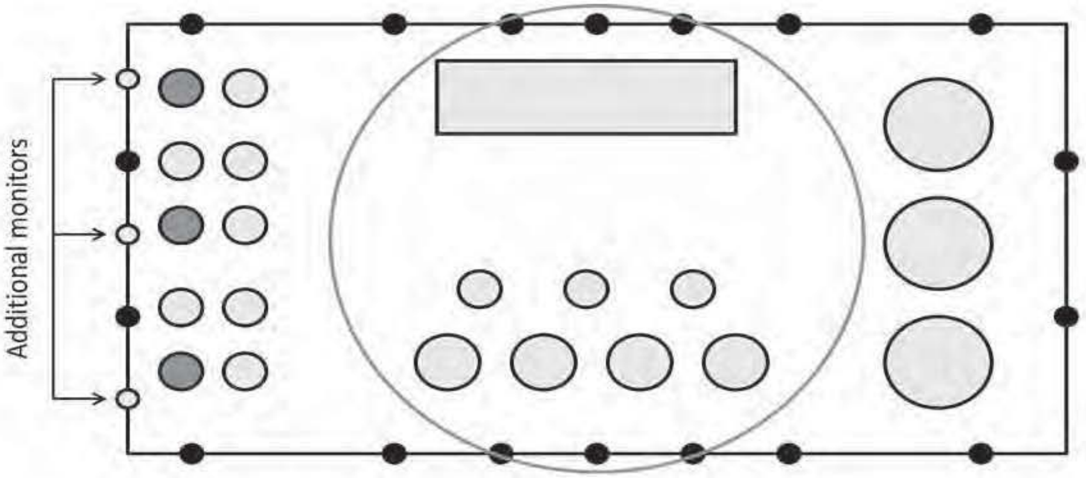
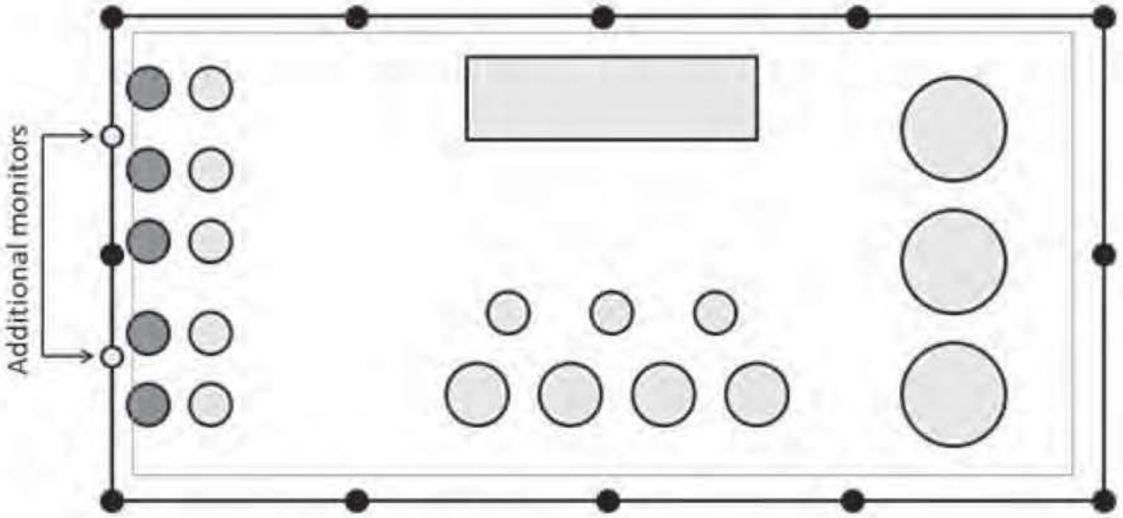


Note: Shaded sources are within 50 meters of the property boundary and are located between two monitors. Additional coverage required by this method was accomplished by placing the monitors halfway between two existing monitors.

Figure 8.1. Facility with a Regular Shape Between 750 and 1,500 Acres in Area



Note: Shaded sources are within 50 meters of the property boundary and are located between two monitors. Additional coverage required by this method was accomplished by placing the monitors halfway between two existing monitors.

Figure 8.2. Facility with a Boundary Length of 24,000 feet

8.2.2 Option 1 for Determining Sampling Locations.

8.2.2.1 For facilities with a regular (circular, triangular, rectangular, or square) shape, determine the geographic center of the facility.

8.2.2.1.1 For facilities with an area of less than or equal to 750 acres, measure angles of 30 degrees from the center point for a total of twelve 30 degree measurements evenly spaced (±1 degree).

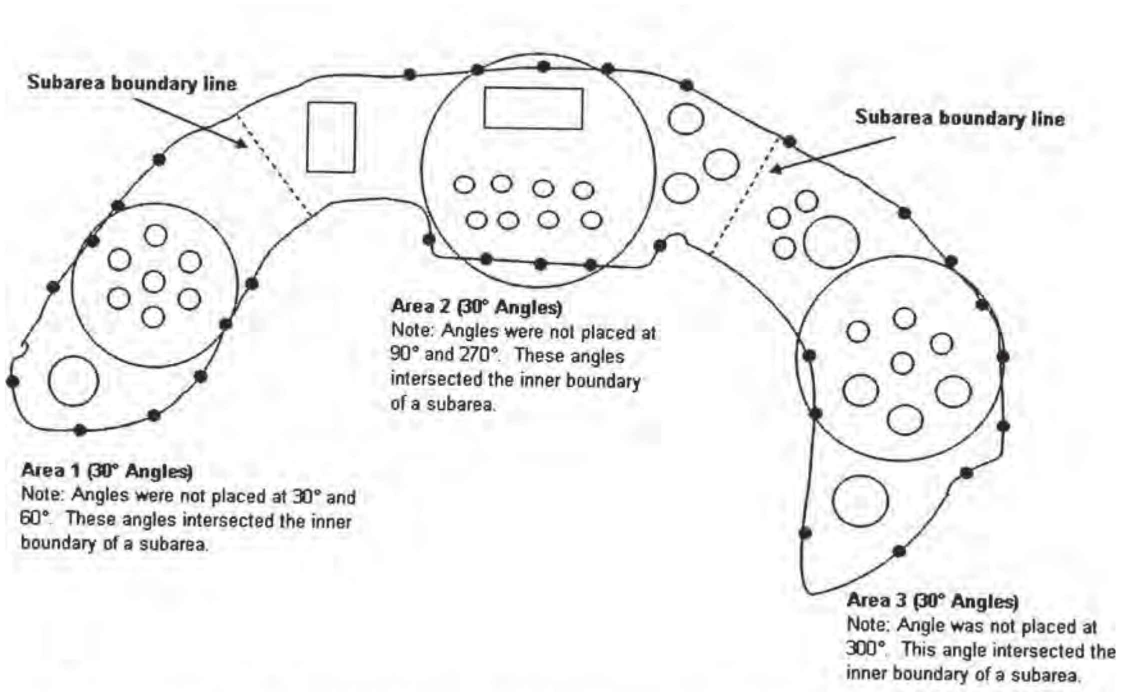
8.2.2.1.2 For facilities covering an area greater than 750 acres but less than or equal to 1,500 acres, measure angles of 20 degrees from the center point for a total of eighteen 20 degree measurements evenly spaced (±1 degree). Figure 8.1 shows the monitor placement around the property boundary of a facility with an area between 750 and 1,500 acres. Monitor placements are represented with black dots along the property boundary.

8.2.2.1.3 For facilities covering an area greater than 1,500 acres, measure angles of 15 degrees from the center point for a total of twenty-four 15 degree measurements evenly spaced (±1 degree).

8.2.2.1.4 Locate each sampling point where the measured angle intersects the outer monitoring perimeter.

8.2.2.2 For irregularly shaped facilities, divide the area into a set of connecting subarea circles, triangles or rectangles to determine sampling locations. The subareas must be defined such that a circle can reasonably encompass the subarea. Then determine the geometric center point of each of the subareas.

8.2.2.2.1 If a subarea is less than or equal to 750 acres (*e.g.,* Figure 8.3), measure angles of 30 degrees from the center point for a total of twelve 30 degree measurements (±1 degree).



Area 2 (30° Angles)
Note: Angles were not placed at 90° and 270°. These angles intersected the inner boundary of a subarea.

Area 1 (30° Angles)
Note: Angles were not placed at 30° and 60°. These angles intersected the inner boundary of a subarea.

Area 3 (30° Angles)
Note: Angle was not placed at 300°. This angle intersected the inner boundary of a subarea.

Figure 8.3. Facility Divided into Three Subareas

8.2.2.2.2 If a subarea is greater than 750 acres but less than or equal to 1,500 acres (*e.g.,* Figure 8.4), measure angles of 20 degrees from the center point for a total of eighteen 20 degree measurements (±1 degree).

8.2.2.2.3 If a subarea is greater than 1,500 acres, measure angles of 15 degrees from the center for a total of twenty-four 15 degree measurements (±1 degree).

8.2.2.2.4 Locate each sampling point where the measured angle intersects the outer monitoring perimeter. Sampling points need not be placed closer than 152 meters (500 feet) apart (or 76 meters (250 feet) if known sources are within 50 meters (162 feet) of the monitoring perimeter), as long as a minimum of 3 monitoring locations are used for each subarea.

8.2.2.2.5 Sampling sites are not needed at the intersection of an inner boundary with an adjacent subarea. The sampling location must be sited where the measured angle intersects the subarea's outer monitoring perimeter.

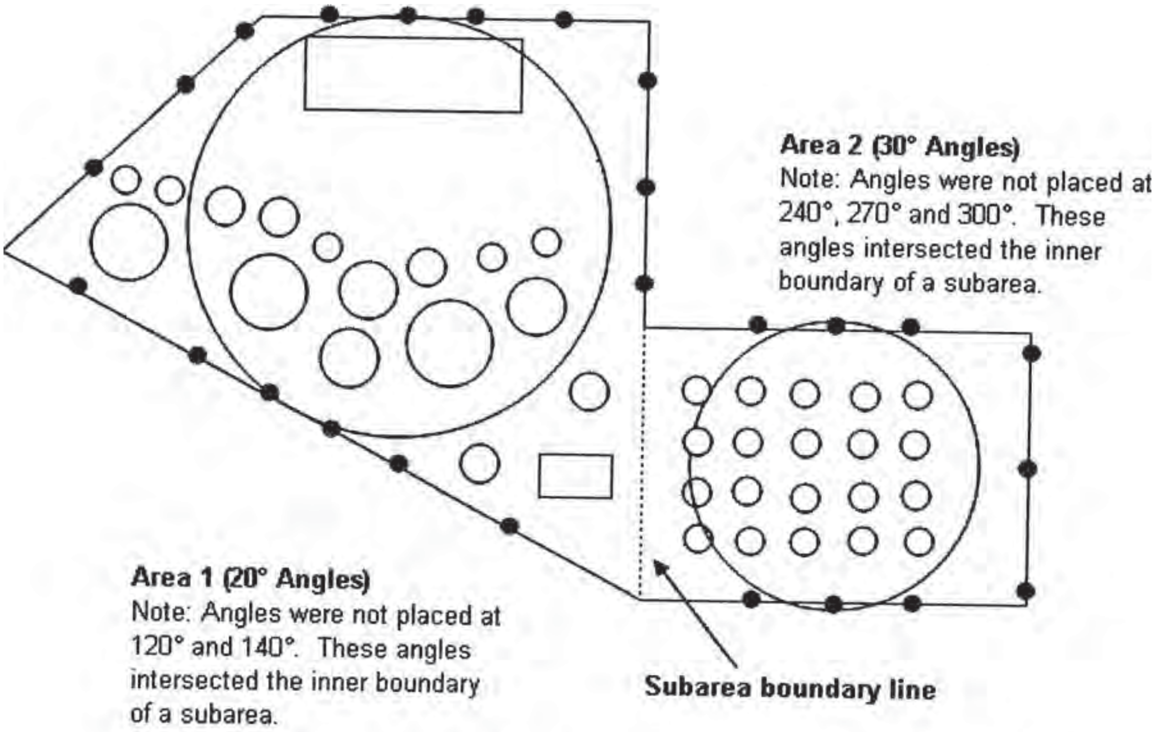


Figure 8.4. Facility Divided into Two Subareas

8.2.3 Option 2 for Determining Sampling Locations.

8.2.3.1 For facilities with a monitoring perimeter length of less than 7,315 meters (24,000 feet), a minimum of twelve sampling locations evenly spaced ±10 percent of the location interval is required.

8.2.3.2 For facilities with a monitoring perimeter length greater than 7,315 meters (24,000 feet), sampling locations are spaced 610 ±76 meters (2,000 ± 250 feet) apart.

8.3 Siting a Meteorological Station

A meteorological station is required at or near the facility you are monitoring. A number of commercially available meteorological stations can be used. Information on meteorological instruments can be found in EPA–454/R–99–005 (Reference 11) (incorporated by reference—see § 63.14). Some important considerations for siting of meteorological stations are detailed below.

8.3.1 Place meteorological stations in locations that represent conditions affecting the transport and dispersion of pollutants in the area of interest. Complex terrain may require the use of more than one meteorological station.

8.3.2 Deploy wind instruments over level, open terrain at a height of 10 meters (33 feet). If possible, locate wind instruments at a distance away from nearby structures that is equal to at least 10 times the height of the structure.

8.3.3 Protect meteorological instruments from thermal radiation and adequately ventilate them using aspirated shields. The temperature sensor must be located at a distance away from any nearby structures that is equal to at least four times the height of the structure. Temperature sensors must be located at least 30 meters (98 feet) from large paved areas.

8.3.4 Collect and record meteorological data, including wind speed, wind direction, temperature and barometric pressure on an hourly basis. Calculate average unit vector wind direction, sigma theta, temperature and barometric pressure per sampling period to enable calculation of concentrations at standard conditions. Supply this information to the laboratory.

8.3.5 Identify and record the location of the meteorological station by its GPS coordinate.

8.4 Monitoring Frequency

8.4.1 Sample collection may be performed for periods up to 14 days.

8.4.2 A site screening protocol that meets method requirements may be performed by collecting samples for a year where each PS accumulates VOC for a 14-day sampling period. Study results are accumulated for the sampling periods (typically 26) over the course of one calendar year. To the extent practical, sampling tubes should be changed at approximately the same time of day at each of the monitoring sites.

8.5 Passive Sampler Deployment

8.5.1 Clean (conditioned) sorbent tubes must be prepared and packaged by the laboratory as described in Method 325B and must be deployed for sampling within 30 days of conditioning.

8.5.2 Allow the tubes to equilibrate with ambient temperature (approximately 30 minutes to 1 hour) at the monitoring location before removing them from their storage/shipping container for sample collection.

8.5.3 If there is any risk that the analytical equipment will not meet the requirement to exclude contamination on outer tube surfaces from the sample flow path (see Section 6.6 of Method 325B), sample handlers must wear clean, white, cotton or powder-free nitrile gloves during PS deployment and collection and throughout any other tube handling operations.

8.5.4 Inspect the sampling tubes immediately prior to deployment. Ensure that they are intact, securely capped, and in good condition. Any suspect tubes (*e.g.*, tubes that appear to have leaked sorbent) should be removed from the sampling set.

8.5.5 Secure passive samplers so the bottom of the diffusive sampling cap is 1.5 to 3 meters (4.9 to 9.8 feet) above ground using a pole or other secure structure at each sampling location. Orient the PS vertically and with the sampling end pointing downward to avoid ingress of particulates.

Note: Duplicate sampling assemblies must be deployed in at least one monitoring location for every 10 monitoring locations during each field monitoring period.

8.5.6 Protect the PS from rain and excessive wind velocity by placing them under the type of protective hood described in Section 6.1.3 or equivalent.

8.5.7 Remove the storage cap on the sampling end of the tube and replace it with a diffusive sampling cap at the start of the sampling period. Make sure the diffusion cap is properly seated and store the removed storage caps in the empty tube shipping container.

8.5.8 Record the start time and location details for each sampler on the field sample data sheet (see example in Section 17.0.).

8.5.9 Expose the sampling tubes for the required sampling period-normally 14-days.

8.5.10 Field blank tubes (see Section 9.3 of Method 325B) are stored outside the shipping container at representative sampling locations around the site, but with both long-term storage caps kept in place throughout the monitoring exercise. Collect at least two field blanks sorbent samples per sampling period to ensure sample integrity associated with shipment, collection, and storage.

8.6 Sorbent Tube Recovery and Meteorological Data Collection

Recover deployed sampling tubes and field blanks as follows:

8.6.1 After the sampling period is complete, immediately replace the diffusion end cap on each sampled tube with a long-term storage end cap. Tighten the seal securely by hand and then tighten an additional quarter turn with an appropriate tool. Record the stop date and time and any additional relevant information on the sample data sheet.

8.6.2 Place the sampled tubes, together with the field blanks, in the storage/shipping container. Label the storage container, but do not use paints, markers, or adhesive labels to identify the tubes. TD-compatible electronic (radio frequency identification (RFID)) tube labels are available commercially and are compatible with some brands of thermal desorber. If used, these may be programmed with relevant tube and sample information, which can be read and automatically transcribed into the sequence report by the TD system.

Note: Sampled tubes must not be placed in the same shipping container as clean conditioned sampling tubes.

8.6.3 Sampled tubes may be shipped at ambient temperature to a laboratory for sample analysis.

8.6.4 Specify whether the tubes are field blanks or were used for sampling and document relevant information for each tube using a Chain of Custody form (see example in Section 17.0) that accompanies the samples from preparation of the tubes through receipt for analysis, including the following information: Unique tube identification numbers for each sampled tube; the date, time, and location code for each PS placement; the date, time, and location code for each PS recovery; the GPS reference for each sampling location; the unique identification number of the duplicate sample (if applicable); and problems or anomalies encountered.

8.6.5 If the sorbent tubes are supplied with electronic (*e.g.,* RFID) tags, it is also possible to allocate a sample identifier to each PS tube. In this case, the recommended format for the identification number of each sampled tube is AA–BB–CC–DD–VOC, where:

AA = Sequence number of placement on route (01, 02, 03 . . .)
BB = Sampling location code (01, 02, 03 . . .)
CC = 14-day sample period number (01 to 26)
DD = Sample code (SA = sample, DU = duplicate, FB = field blank)
VOC = 3-letter code for target compound(s) (*e.g.,* BNZ for benzene or BTX for benzene, toluene, and xylenes)

Note: Sampling start and end times/dates can also be logged using RFID tube tags.

9.0 Quality Control

9.1 Most quality control checks are carried out by the laboratory and associated requirements are in Section 9.0 of Method 325B, including requirements for laboratory blanks, field blanks, and duplicate samples.

9.2 Evaluate for potential outliers the laboratory results for neighboring sampling tubes collected over the same time period. A potential outlier is a result for which one or more PS tube does not agree with the trend in results shown by neighboring PS tubes—particularly when data from those locations have been more consistent during previous sampling periods. Accidental contamination by the sample handler must be documented before any result can be eliminated as an outlier. Rare but possible examples of contamination include loose or missing storage caps or contaminated storage/shipping containers. Review data from the same and neighboring monitoring locations for the subsequent sampling periods. If the anomalous result is not repeated for that monitoring location, the episode can be ascribed to transient contamination and the data in question must be flagged for potential elimination from the dataset.

9.3 Duplicates and Field Blanks

9.3.1 Collect at least one co-located/duplicate sample for every 10 field samples to determine precision of the measurements.

9.3.2 Collect at least two field blanks sorbent samples per sampling period to ensure sample integrity associated with shipment, collection, and storage. You must use the entire sampling apparatus for field blanks including unopened sorbent tubes mounted in protective sampling hoods. The tube closures must not be removed. Field blanks must be placed in two different quadrants (*e.g.,* 90° and 270°) and remain at the sampling location for the sampling period.

10.0 Calibration and Standardization

Follow the calibration and standardization procedures for meteorological measurements in EPA–454/B–08–002 March 2008 (Reference 11) (incorporated by reference—see § 63.14). Refer to Method 325B for calibration and standardization procedures for analysis of the passive sampling tubes.

11.0 Analytical Procedures

Refer to Method 325B, which provides details for the preparation and analysis of sampled passive monitoring tubes (preparation of sampling tubes, shipment and storage of exposed sampling tubes, and analysis of sampling tubes).

12.0 Data Analysis, Calculations and Documentation

12.1 Calculate Annual Average Fenceline Concentration.

After a year's worth of sampling at the facility fenceline (for example, 26 14-day samples), the average (PS_i) may be calculated for any specified period at each PS location using Equation 12.1.

$$PS_i = \frac{\sum PS_{ip}}{N} \qquad \text{Eq. 12.1}$$

Where:
PS_i = Annual average for location *i.*
PS_{ip} = Sampling period specific concentration from Method 325B.
i = Location of passive sampler (0 to 360°).
p = The sampling period.
N = The number of sampling periods in the year (*e.g.,* for 14-day sampling periods, from 1 to 26).

Note: PS_{ip} is a function of sampling location-specific factors such as the contribution from facility sources, unusual localized meteorological conditions, contribution from nearby interfering sources, the background caused by integrated far-field sources and measurement error due to deployment, handling, siting, or analytical errors.

12.2 Identify Sampling Locations of Interest

If data from neighboring sampling locations are significantly different, then you may add extra sampling points to isolate background contributions or identify facility-specific "hot spots."

12.3 Evaluate Trends

You may evaluate trends and patterns in the PS data over multiple sampling periods to determine if elevated concentrations of target compounds are due to operations on the facility or if contributions from background sources are significant.

12.3.1 Obtain meteorological data including wind speed and wind direction or unit vector wind data from the on-site meteorological station. Use this meteorological data to determine the prevailing wind direction and speed during the periods of elevated concentrations.

12.3.2 As an option you may perform preliminary back trajectory calculations (*http://ready.arl.noaa.gov/HYSPLIT.php*) to aid in identifying the source of the background contribution to elevated target compound concentrations.

12.3.3 Information on published or documented events on- and off-site may also be included in the associated sampling period report to explain elevated concentrations if relevant. For example, you would describe if there was a chemical spill on site, or an accident on an adjacent road.

12.3.4 Additional monitoring for shorter periods (See section 8.4) may be necessary to allow better discrimination/resolution of contributing emission sources if the measured trends and associated meteorology do not provide a clear assessment of facility contribution to the measured fenceline concentration.

12.3.5 Additional records necessary to calculate sampling period average target compound concentration can be found in Section 12.1 of Method 325B.

13.0 Method Performance

Method performance requirements are described in Method 325B.

14.0 Pollution Prevention

[Reserved]

15.0 Waste Management

[Reserved]

16.0 References

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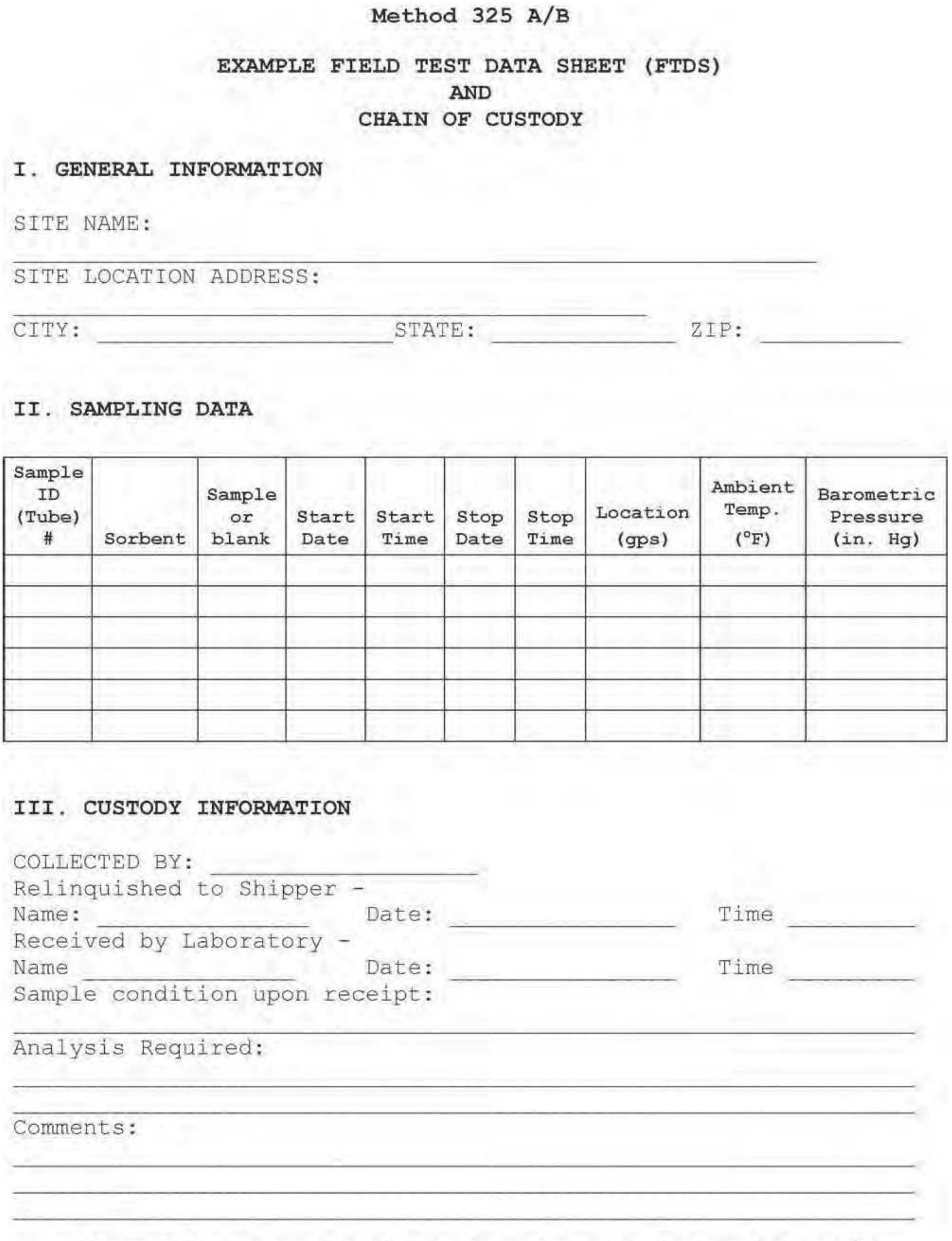
17.0 Tables, Diagrams, Flowcharts and Validation Data



Method 325 A/B

EXAMPLE FIELD TEST DATA SHEET (FTDS)
AND
CHAIN OF CUSTODY

I. GENERAL INFORMATION

SITE NAME: ____________________

SITE LOCATION ADDRESS: ____________________

CITY: ____________________ STATE: ____________ ZIP: __________

II. SAMPLING DATA

Sample ID (Tube) #	Sorbent	Sample or blank	Start Date	Start Time	Stop Date	Stop Time	Location (gps)	Ambient Temp. (°F)	Barometric Pressure (in. Hg)

III. CUSTODY INFORMATION

COLLECTED BY: ____________________

Relinquished to Shipper -

Name: ________________ Date: __________________ Time __________

Received by Laboratory -

Name ________________ Date: __________________ Time __________

Sample condition upon receipt:

____

Analysis Required:

____

____

Comments:

____

____

____

Figure 17.1. Example Field Data Form and Chain of Custody

Method 325B—Volatile Organic Compounds from Fugitive and Area Sources:

Sampler Preparation and Analysis

1.0 Scope and Application

1.1 This method describes thermal desorption/gas chromatography (TD/GC) analysis of volatile organic compounds (VOCs) from fugitive and area emission sources collected onto sorbent tubes using passive sampling. It could also be applied to the TD/GC analysis of VOCs collected using active (pumped) sampling onto sorbent tubes. The concentration of airborne VOCs at or near potential fugitive- or area-emission sources may be determined using this method in combination with Method 325A. Companion Method 325A (Sampler Deployment and VOC Sample Collection) describes procedures for deploying the sorbent tubes and passively collecting VOCs.

1.2 The preferred GC detector for this method is a mass spectrometer (MS), but flame ionization detectors (FID) may also be used. Other conventional GC detectors such as electron capture (ECD), photoionization (PID), or flame photometric (FPD) may also be used if they are selective and sensitive to the target compound(s) and if they meet the method performance criteria provided in this method.

1.3 There are 97 VOCs listed as hazardous air pollutants in Title III of the Clean Air Act Amendments of 1990. Many of these VOC are candidate compounds for this method. Compounds with known uptake rates for Carbograph™ 1 TD, Carbopack™ B, or Carbopack™ X are listed in Table 12.1. This method provides performance criteria to demonstrate acceptable performance of the method (or modifications of the method) for monitoring one or more of the compounds listed Table 12.1. If standard passive sampling tubes are packed with other sorbents or used for other analytes than those listed in Table 12.1, then method performance and relevant uptake rates should be verified according to Addendum A to this method or by one of the following national/international standard methods: ISO 16017–2:2003(E), ASTM D6196–03 (Reapproved 2009), or BS EN 14662–4:2005 (all incorporated by reference—see § 63.14), or reported in the peer-reviewed open literature.

1.4 The analytical approach using TD/GC/MS is based on previously published EPA guidance in Compendium Method TO–17 (*http://www.epa.gov/ttnamti1/airtox.html#compendium*) (Reference 1), which describes active (pumped) sampling of VOCs from ambient air onto tubes packed with thermally stable adsorbents.

1.5 Inorganic gases not suitable for analysis by this method include oxides of carbon, nitrogen and sulfur, ozone (O_3), and other diatomic permanent gases. Other pollutants not suitable for this analysis method include particulate pollutants, (*i.e.*, fumes, aerosols, and dusts), compounds too labile (reactive) for conventional GC analysis, and VOCs that are more volatile than propane.

2.0 Summary of Method

2.1 This method provides procedures for the preparation, conditioning, blanking, and shipping of sorbent tubes prior to sample collection.

2.2 Laboratory and field personnel must have experience of sampling trace-level VOCs using sorbent tubes (References 2,5) and must have experience operating thermal desorption/GC/multi-detector instrumentation.

2.3 Key steps of this method as implemented for each sample tube include: Stringent leak testing under stop flow, recording ambient temperature conditions, adding internal standards, purging the tube, thermally desorbing the sampling tube, refocusing on a focusing trap, desorbing and transferring/injecting the VOCs from the secondary trap into the capillary GC column for separation and analysis.

2.4 Water management steps incorporated into this method include: (a) Selection of hydrophobic sorbents in the sampling tube; (b) optional dry purging of sample tubes prior to analysis; and (c) additional selective elimination of water during primary (tube) desorption (if required) by selecting trapping sorbents and temperatures such that target compounds are quantitatively retained while water is purged to vent.

3.0 Definitions

(See also Section 3.0 of Method 325A).

3.1 Blanking is the desorption and confirmatory analysis of conditioned sorbent tubes before they are sent for field sampling.

3.2 *Breakthrough volume and associated relation to passive sampling.* Breakthrough volumes, as applied to active sorbent tube sampling, equate to the volume of air containing a constant concentration of analyte that may be passed through a sorbent tube at a given temperature before a detectable level (5 percent) of the input analyte concentration elutes from the tube. Although breakthrough volumes are directly related to active rather than passive sampling, they provide a measure of the strength of the sorbent-sorbate interaction and therefore also relate to the efficiency of the passive sampling process. The best direct measure of passive sampling efficiency is the stability of the uptake rate. Quantitative passive sampling is compromised when the sorbent no longer acts as a perfect sink—*i.e.*, when the concentration of a target analyte immediately above the sorbent sampling surface no longer approximates to zero. This causes a reduction in the uptake rate over time. If the uptake rate for a given analyte on a given sorbent tube remains relatively constant —*i.e.*, if the uptake rate determined for 48 hours is similar to that determined for 7 or 14 days—the user can be confident that passive sampling is occurring at a constant rate. As a general rule of thumb, such ideal passive sampling conditions typically exist for analyte:sorbent combinations where the breakthrough volume exceeds 100 L (Reference 4).

3.3 *Continuing calibration verification sample (CCV).* Single level calibration samples run periodically to confirm that the analytical system continues to generate sample results within acceptable agreement to the current calibration curve.

3.4 *Focusing trap* is a cooled, secondary sorbent trap integrated into the analytical thermal desorber. It typically has a smaller i.d. and lower thermal mass than the original sample tube allowing it to effectively refocus desorbed analytes and then heat rapidly to ensure efficient transfer/injection into the capillary GC analytical column.

3.5 *High Resolution Capillary Column Chromatography* uses fused silica capillary columns with an inner diameter of 320 µm or less and with a stationary phase film thickness of 5 µm or less.

3.6 *h* is time in hours.

3.7 *i.d.* is inner diameter.

3.8 *min* is time in minutes.

3.9 *Method Detection Limit* is the lowest level of analyte that can be detected in the sample matrix with 99% confidence.

3.10 *MS–SCAN* is the mode of operation of a GC quadrupole mass spectrometer detector that measures all ions over a given mass range over a given period of time.

3.11 *MS–SIM* is the mode of operation of a GC quadrupole mass spectrometer detector that measures only a single ion or a selected number of discrete ions for each analyte.

3.12 *o.d.* is outer diameter.

3.13 *ppbv* is parts per billion by volume.

3.14 *Thermal desorption* is the use of heat and a flow of inert (carrier) gas to extract volatiles from a solid matrix. No solvent is required.

3.15 *Total ion chromatogram* is the chromatogram produced from a mass spectrometer detector collecting full spectral information.

3.16 *Two-stage thermal desorption* is the process of thermally desorbing analytes from a sorbent tube, reconcentrating them on a focusing trap (see Section 3.4), which is then itself rapidly heated to ‘‘inject’’ the concentrated compounds into the GC analyzer.

3.17 *VOC* is volatile organic compound.

4.0 Analytical Interferences

4.1 *Interference from Sorbent Artifacts.* Artifacts may include target analytes as well as other VOC that co-elute chromatographically with the compounds of interest or otherwise interfere with the identification or quantitation of target analytes.

4.1.1 Sorbent decomposition artifacts are VOCs that form when sorbents degenerate, *e.g.,* when exposed to reactive species during sampling. For example, benzaldehyde, phenol, and acetophenone artifacts are reported to be formed via oxidation of the polymeric sorbent Tenax® when sampling high concentration (100–500 ppb) ozone atmospheres (Reference 5).

4.1.2 Preparation and storage artifacts are VOCs that were not completely cleaned from the sorbent tube during conditioning or that are an inherent feature of that sorbent at a given temperature.

4.2 *Humidity.* Moisture captured during sampling can interfere with VOC analysis. Passive sampling using tubes packed with hydrophobic sorbents, like those described in this method, minimizes water retention. However, if water interference is found to be an issue under extreme conditions, one or more of the water management steps described in Section 2.4 can be applied.

4.3 *Contamination from Sample Handling.* The type of analytical thermal desorption equipment selected should exclude the possibility of outer tube surface contamination entering the sample flow path (see Section 6.6). If the available system does not meet this requirement, sampling tubes and caps must be handled only while wearing clean, white cotton or powder free nitrile gloves to prevent contamination with body oils, hand lotions, perfumes, etc.

5.0 Safety

5.1 This method does not address all of the safety concerns associated with its use. It is the responsibility of the user of this standard to establish appropriate field and laboratory safety and health practices prior to use.

5.2 Laboratory analysts must exercise extreme care in working with high-pressure gas cylinders.

5.3 Due to the high temperatures involved, operators must use caution when conditioning and analyzing tubes.

6.0 Equipment and Supplies

6.1 *Tube Dimensions and Materials.* The sampling tubes for this method are 3.5-inches (89 mm) long, ¼ inch (6.4 mm) o.d., and 5 mm i.d. passive sampling tubes (see Figure 6.1). The tubes are made of inert-coated stainless steel with the central section (up to 60 mm) packed with sorbent, typically supported between two 100 mesh stainless steel gauze. The tubes have a cross sectional area of 19.6 square mm (5 mm i.d.). When used for passive sampling, these tubes have an internal diffusion (air) gap (DG) of 1.5 cm between the sorbent retaining gauze at the sampling end of the tube, and the gauze in the diffusion cap.

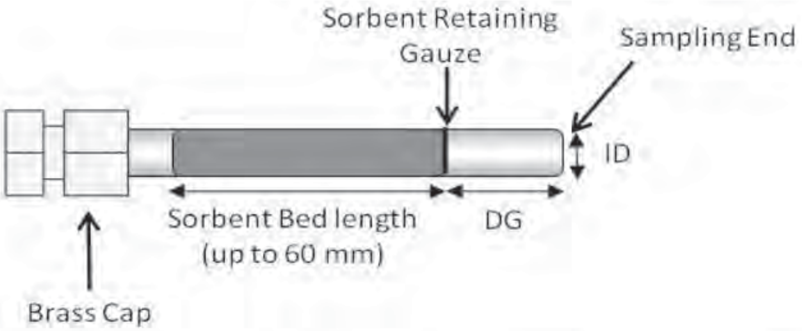


Figure 6.1. Cross Section View of Passive Sorbent Tube

6.2 Tube Conditioning Apparatus

6.2.1 Freshly packed or newly purchased tubes must be conditioned as described in Section 9 using an appropriate dedicated tube conditioning unit or the thermal desorber. Note that the analytical TD system should be used for tube conditioning if it supports a dedicated tube conditioning mode in which effluent from contaminated tubes is directed to vent without passing through key parts of the sample flow path such as the focusing trap.

6.2.2 Dedicated tube conditioning units must be leak-tight to prevent air ingress, allow precise and reproducible temperature selection (±5 °C), offer a temperature range at least as great as that of the thermal desorber, and support inert gas flows in the range up to 100 mL/min.

Note: For safety and to avoid laboratory contamination, effluent gases from freshly packed or highly contaminated tubes should be passed through a charcoal filter during the conditioning process to prevent desorbed VOCs from polluting the laboratory atmosphere.

6.3 Tube Labeling

6.3.1 Label the sample tubes with a unique permanent identification number and an indication of the sampling end of the tube. Labeling options include etching and TD-compatible electronic (radio frequency identification (RFID)) tube labels.

6.3.2 To avoid contamination, do not make ink markings of any kind on clean sorbent tubes or apply adhesive labels.

Note: TD-compatible electronic (RFID) tube labels are available commercially and are compatible with some brands of thermal desorber. If used, these may be programmed with relevant tube and sample information, which can be read and automatically transcribed into the sequence report by the TD system (see Section 8.6 of Method 325A).

6.4 Blank and Sampled Tube Storage Apparatus

6.4.1 Long-term storage caps. Seal clean, blank and sampled sorbent tubes using inert, long-term tube storage caps comprising non-greased, 2-piece, 0.25-inch, metal SwageLok®-type screw caps fitted with combined polytetrafluoroethylene ferrules.

6.4.2 Storage and transportation containers. Use clean glass jars, metal cans or rigid, non-emitting polymer boxes.

Note: You may add a small packet of new activated charcoal or charcoal/silica gel to the shipping container for storage and transportation of batches of conditioned sorbent tubes prior to use. Coolers without ice packs make suitable shipping boxes for containers of tubes because the coolers help to insulate the samples from extreme temperatures (*e.g.,* if left in a parked vehicle).

6.5 Unheated GC Injection Unit for Loading Standards Onto Blank Tubes

A suitable device has a simple push fit or finger-tightening connector for attaching the sampling end of blank sorbent tubes without damaging the tube. It also has a means of controlling carrier gas flow through the injector and attached sorbent tube at 50–100 mL/min and includes a low emission septum cap that allows the introduction of gas or liquid standards via appropriate syringes. Reproducible and quantitative transfer of higher boiling compounds in liquid standards is facilitated if the injection unit allows the tip of the syringe to just touch the sorbent retaining gauze inside the tube.

6.6 Thermal Desorption Apparatus

The manual or automated thermal desorption system must heat sorbent tubes while a controlled flow of inert (carrier) gas passes through the tube and out of the sampling end. The apparatus must also incorporate a focusing trap to quantitatively refocus compounds desorbed from the tube. Secondary desorption of the focusing trap should be fast/efficient enough to transfer the compounds into the high resolution capillary GC column without band broadening and without any need for further pre- or on-column focusing. Typical TD focusing traps comprise small sorbent traps (Reference 16) that are electrically-cooled using multistage Peltier cells (References 17, 18). The direction of gas flow during trap desorption should be the reverse of that used for focusing to extend the compatible analyte volatility range. Closed cycle coolers offer another cryogen-free trap cooling option. Other TD system requirements and operational stages are described in Section 11 and in Figures 17–2 through 17–4.

6.7 Thermal Desorber—GC Interface

6.7.1 The interface between the thermal desorber and the GC must be heated uniformly and the connection between the transfer line insert and the capillary GC analytical column itself must be leak tight.

6.7.2 A portion of capillary column can alternatively be threaded through the heated transfer line/TD interface and connected directly to the thermal desorber.

Note: Use of a metal syringe-type needle or unheated length of fused silica pushed through the septum of a conventional GC injector is not permitted as a means of interfacing the thermal desorber to the chromatograph. Such connections result in cold spots, cause band broadening and are prone to leaks.

6.8 GC/MS Analytical Components

6.8.1 The GC system must be capable of temperature programming and operation of a high resolution capillary column. Depending on the choice of column (*e.g.*, film thickness) and the volatility of the target compounds, it may be necessary to cool the GC oven to subambient temperatures (*e.g.*, −50 °C) at the start of the run to allow resolution of very volatile organic compounds.

6.8.2 All carrier gas lines supplying the GC must be constructed from clean stainless steel or copper tubing. Non-polytetrafluoroethylene thread sealants. Flow controllers, cylinder regulators, or other pneumatic components fitted with rubber components are not suitable.

6.9 Chromatographic Columns

High-resolution, fused silica or equivalent capillary columns that provide adequate separation of sample components to permit identification and quantitation of target compounds must be used.

Note: 100-percent methyl silicone or 5-percent phenyl, 95-percent methyl silicone fused silica capillary columns of 0.25- to 0.32-mm i.d. of varying lengths and with varying thicknesses of stationary phase have been used successfully for non-polar and moderately polar compounds. However, given the diversity of potential target lists, GC column choice is left to the operator, subject to the performance criteria of this method.

6.10 Mass Spectrometer

Linear quadrupole, magnetic sector, ion trap or time-of-flight mass spectrometers may be used provided they meet specified performance criteria. The mass detector must be capable of collecting data from 35 to 300 atomic mass units (amu) every 1 second or less, utilizing 70 volts (nominal) electron energy in the electron ionization mode, and producing a mass spectrum that meets all the instrument performance acceptance criteria in Section 9 when 50 ηg or less of p-bromofluorobenzene is analyzed.

7.0 Reagents and Standards

7.1 Sorbent Selection

7.1.1 Use commercially packed tubes meeting the requirements of this method or prepare tubes in the laboratory using sieved sorbents of particle size in the range 20 to 80 mesh that meet the retention and quality control requirements of this method.

7.1.2 This passive air monitoring method can be used without the evaluation specified in Addendum A if the type of tubes described in Section 6.1 are packed with 4–6 cm (typically 400–650 mg) of the sorbents listed in Table 12.1 and used for the respective target analytes.

Note: Although Carbopack™ X is the optimum sorbent choice for passive sampling of 1,3-butadiene, recovery of compounds with vapor pressure lower than benzene may be difficult to achieve without exceeding sorbent maximum temperature limitations (see Table 8.1). See ISO 16017–2:2003(E) or ASTM D6196–03 (Reapproved 2009) (both incorporated by reference—see § 63.14) for more details on sorbent choice for air monitoring using passive sampling tubes.

7.1.3 If standard passive sampling tubes are packed with other sorbents or used for analytes other than those tabulated in Section 12.0, method performance and relevant uptake rates should be verified according to Addendum A to this method or by following the techniques described in one of the following national/international standard methods: ISO 16017–2:2003(E), ASTM D6196–03 (Reapproved 2009), or BS EN 14662–4:2005 (all incorporated by reference—see § 63.14)—or reported in the peer-reviewed open literature. A summary table and the supporting evaluation data demonstrating the selected sorbent meets the requirements in Addendum A to this method must be submitted to the regulatory authority as part of a request to use an alternative sorbent.

7.1.4 Passive (diffusive) sampling and thermal desorption methods that have been evaluated at relatively high atmospheric concentrations (*i.e.,* mid-ppb to ppm) and published for use in workplace air and industrial/mobile source emissions testing (References 9–20) may be applied to this procedure. However, the validity of any shorter term uptake rates must be verified and adjusted if necessary for the longer monitoring periods required by this method by following procedures described in Addendum A to this method or those presented in national/international standard methods: ISO 16017–2:2003(E), ASTM D6196–03 (Reapproved 2009), or BS EN 14662–4:2005 (all incorporated by reference-see § 63.14).

7.1.5 Suitable sorbents for passive sampling must have breakthrough volumes of at least 20 L (preferably >100 L) for the compounds of interest and must quantitatively release the analytes during desorption without exceeding maximum temperatures for the sorbent or instrumentation.

7.1.6 Repack/replace the sorbent tubes or demonstrate tube performance following the requirements in Addendum A to this method at least every 2 years or every 50 uses, whichever occurs first.

7.2 Gas Phase Standards

7.2.1 Static or dynamic standard atmospheres may be used to prepare calibration tubes and/or to validate passive sampling uptake rates and can be generated from pure chemicals or by diluting concentrated gas standards. The standard atmosphere must be stable at ambient pressure and accurate to ±10 percent of the target gas concentration. It must be possible to maintain standard atmosphere concentrations at the same or lower levels than the target compound concentration objectives of the test. Test atmospheres used for validation of uptake rates must also contain at least 35 percent relative humidity.

Note: Accurate, low-(ppb-) level gas-phase VOC standards are difficult to generate from pure materials and may be unstable depending on analyte polarity and volatility. Parallel monitoring of vapor concentrations with alternative methods, such as pumped sorbent tubes or sensitive/selective on-line detectors, may be necessary to minimize uncertainty. For these reasons, standard atmospheres are rarely used for routine calibration.

7.2.2 Concentrated, pressurized gas phase standards. Accurate (±5 percent or better), concentrated gas phase standards supplied in pressurized cylinders may also be used for calibration. The concentration of the standard should be such that a 0.5–5.0 mL volume contains approximately the same mass of analytes as will be collected from a typical air sample.

7.2.3 Follow manufacturer's guidelines concerning storage conditions and recertification of the concentrated gas phase standard. Gas standards must be recertified a minimum of once every 12 months.

7.3 Liquid Standards

Target analytes can also be introduced to the sampling end of sorbent tubes in the form of liquid calibration standards.

7.3.1 The concentration of liquid standards must be such that an injection of 0.5–2 µl of the solution introduces the same mass of target analyte that is expected to be collected during the passive air sampling period.

7.3.2 Solvent Selection. The solvent selected for the liquid standard must be pure (contaminants <10 percent of minimum analyte levels) and must not interfere chromatographically with the compounds of interest.

7.3.3 If liquid standards are sourced commercially, follow manufacturer's guidelines concerning storage conditions and shelf life of unopened and opened liquid stock standards.

Note: Commercial VOC standards are typically supplied in volatile or non-interfering solvents such as methanol.

7.3.4 Working standards must be stored at 6 °C or less and used or discarded within two weeks of preparation.

7.4 Gas Phase Internal Standards

7.4.1 Gas-phase deuterated or fluorinated organic compounds may be used as internal standards for MS-based systems.

7.4.2 Typical compounds include deuterated toluene, perfluorobenzene and perfluorotoluene.

7.4.3 Use multiple internal standards to cover the volatility range of the target analytes.

7.4.4 Gas-phase standards must be obtained in pressurized cylinders and containing vendor certified gas concentrations accurate to ±5 percent. The concentration should be such that the mass of internal standard components introduced is similar to those of the target analytes collected during field monitoring.

7.5 Preloaded Standard Tubes

Certified, preloaded standard tubes, accurate within ±5 percent for each analyte at the microgram level and ±10 percent at the nanogram level, are available commercially and may be used for auditing and quality control purposes. (See Section 9.5 for audit accuracy evaluation criteria.) Certified preloaded tubes may also be used for routine calibration.

Note: Proficiency testing schemes are also available for TD/GC/MS analysis of sorbent tubes preloaded with common analytes such as benzene, toluene, and xylene.

7.6 Carrier Gases

Use inert, 99.999-percent or higher purity helium as carrier gas. Oxygen and organic filters must be installed in the carrier gas lines supplying the analytical system according to the manufacturer's instructions. Keep records of filter and oxygen scrubber replacement.

8.0 Sorbent Tube Handling (Before and After Sampling)

8.1 Sample Tube Conditioning

8.1.1 Sampling tubes must be conditioned using the apparatus described in Section 6.2.

8.1.2 New tubes should be conditioned for 2 hours to supplement the vendor's conditioning procedure. Recommended temperatures for tube conditioning are given in Table 8.1.

8.1.3 After conditioning, the blank must be verified on each new sorbent tube and on 10 percent of each batch of reconditioned tubes. See Section 9.0 for acceptance criteria.

TABLE 8.1—EXAMPLE SORBENT TUBE CONDITIONING PARAMETERS

Sampling sorbent	Maximum temperature (°C)	Conditioning temperature (°C)	Carrier gas flow rate
Carbotrap® C	>400	350	100 mL/min
Carbopack™ C			
Anasorb® GCB2			
Carbograph™ 1 TD			
Carbotrap®			
Carbopack™ B			
Anasorb® GCB1			
Tenax® TA			
Carbopack™ X	350	330	100 mL/min

8.2 Capping, Storage and Shipment of Conditioned Tubes

8.2.1 Conditioned tubes must be sealed using long-term storage caps (see Section 6.4) pushed fully down onto both ends of the PS sorbent tube, tightened by hand and then tighten an additional quarter turn using an appropriate tool.

8.2.2 The capped tubes must be kept in appropriate containers for storage and transportation (see Section 6.4.2). Containers of sorbent tubes may be stored and shipped at ambient temperature and must be kept in a clean environment.

8.2.3 You must keep batches of capped tubes in their shipping boxes or wrap them in uncoated aluminum foil before placing them in their storage container, especially before air freight, because the packaging helps hold caps in position if the tubes get very cold.

8.3 Calculating the Number of Tubes Required for a Monitoring Exercise

8.3.1 Follow guidance given in Method 325A to determine the number of tubes required for site monitoring.

8.3.2 The following additional samples will also be required: Laboratory blanks as specified in Section 9.1.2 (one per analytical sequence minimum), field blanks as specified in Section 9.3.2 (two per sampling period minimum), CCV tubes as specified in Section 10.9.4. (at least one per analysis sequence or every 24 hours), and duplicate samples as specified in Section 9.4 (at least one duplicate sample is required for every 10 sampling locations during each monitoring period).

8.4 Sample Collection

8.4.1 Allow the tubes to equilibrate with ambient temperature (approximately 30 minutes to 1 hour) at the monitoring location before removing them from their storage/shipping container for sample collection.

8.4.2 Tubes must be used for sampling within 30 days of conditioning (Reference 4).

8.4.3 During field monitoring, the long-term storage cap at the sampling end of the tube is replaced with a diffusion cap and the whole assembly is arranged vertically, with the sampling end pointing downward, under a protective hood or shield—See Section 6.1 of Method 325A for more details.

8.5 Sample Storage

8.5.1 After sampling, tubes must be immediately resealed with long-term storage caps and placed back inside the type of storage container described in Section 6.4.2.

8.5.2 Exposed tubes may not be placed in the same container as clean tubes. They should not be taken back out of the container until ready for analysis and after they have had time to equilibrate with ambient temperature in the laboratory.

8.5.3 Sampled tubes must be inspected before analysis to identify problems such as loose or missing caps, damaged tubes, tubes that appear to be leaking sorbent or container contamination. Any and all such problems must be documented together with the unique identification number of the tube or tubes concerned. Affected tubes must not be analyzed but must be set aside.

8.5.4 Intact tubes must be analyzed within 30 days of the end of sample collection (within one week for limonene, carene, bis-chloromethyl ether, labile sulfur or nitrogen-containing compounds, and other reactive VOCs).

Note: Ensure ambient temperatures stay below 23 °C during transportation and storage. Refrigeration is not normally required unless the samples contain reactive compounds or cannot be analyzed within 30 days. If refrigeration is used, the atmosphere inside the refrigerator must be clean and free of organic solvents.

9.0 Quality Control

9.1 Laboratory Blank

The analytical system must be demonstrated to be contaminant free by performing a blank analysis at the beginning of each analytical sequence to demonstrate that the secondary trap and TD/GC/MS analytical equipment are free of any significant interferents.

9.1.1 Laboratory blank tubes must be prepared from tubes that are identical to those used for field sampling.

9.1.2 Analysis of at least one laboratory blank is required per analytical sequence. The laboratory blank must be stored in the laboratory under clean, controlled ambient temperature conditions.

9.1.3 Laboratory blank/artifact levels must meet the requirements of Section 9.2.2 (see also Table 17.1). If the laboratory blank does not meet requirements, stop and perform corrective actions and then re-analyze laboratory blank to ensure it meets requirements.

9.2 Tube Conditioning

9.2.1 Conditioned tubes must be demonstrated to be free of contaminants and interference by running 10 percent of the blank tubes selected at random from each conditioned batch under standard sample analysis conditions (see Section 8.1).

9.2.2 Confirm that artifacts and background contamination are ≤ 0.2 ppbv or less than three times the detection limit of the procedure or less than 10 percent of the target compound(s) mass that would be collected if airborne concentrations were at the regulated limit value, whichever is larger. Only tubes that meet these criteria can be used for field monitoring, field or laboratory blanks, or for system calibration.

9.2.3 If unacceptable levels of VOCs are observed in the tube blanks, then the processes of tube conditioning and checking the blanks must be repeated.

9.3 Field Blanks

9.3.1 Field blank tubes must be prepared from tubes that are identical to those used for field sampling—*i.e.,* they should be from the same batch, have a similar history, and be conditioned at the same time.

9.3.2 Field blanks must be shipped to the monitoring site with the sampling tubes and must be stored at the sampling location throughout the monitoring exercise. The field blanks must be installed under a protective hood/cover at the sampling location, but the long-term storage caps must remain in place throughout the monitoring period (see Method 325A). The field blanks are then shipped back to the laboratory in the same container as the sampled tubes. One field blank tube is required for every 10 sampled tubes on a monitoring exercise and no less than two field blanks should be collected, regardless of the size of the monitoring study.

9.3.3 Field blanks must contain no greater than one-third of the measured target analyte or compliance limit for field samples (see Table 17.1). If either field blank fails, flag all data that do not meet this criterion with a note that the associated results are estimated and likely to be biased high due to field blank background.

9.4 Duplicate Samples

Duplicate (co-located) samples collected must be analyzed and reported as part of method quality control. They are used to evaluate sampling and analysis precision. Relevant performance criteria are given in Section 9.9.

9.5 Method Performance Criteria

Unless otherwise noted, monitoring method performance specifications must be demonstrated for the target compounds using the procedures described in Addendum A to this method and the statistical approach presented in Method 301.

9.6 Method Detection Limit

Determine the method detection limit under the analytical conditions selected (see Section 11.3) using the procedure in Section 15 of Method 301. The method detection limit is defined for each system by making seven replicate measurements of a concentration of the compound of interest within a factor of five of the detection limit. Compute the standard deviation for the seven replicate concentrations, and multiply this value by three. The results should demonstrate that the method is able to detect analytes such as benzene at concentrations as low as 50 ppt or 1/3rd (preferably 1/10th) of the lowest concentration of interest, whichever is larger.

Note: Determining the detection limit may be an iterative process as described in 40 CFR part 136, Appendix B.

9.7 Analytical Bias

Analytical bias must be demonstrated to be within ±30 percent using Equation 9.1. Analytical bias must be demonstrated during initial setup of this method and as part of the CCV carried out with every sequence of 10 samples or less (see Section 9.14). Calibration standard tubes (see Section 10.0) may be used for this purpose.

$$\text{Analytical Bias} = \frac{(\text{Spiked Value} - \text{Measured Value})}{\text{Spiked Value}} \times 100 \qquad \text{Eq. 9.1}$$

Where:

Spiked Value = A known mass of VOCs added to the tube.

Measured Value = Mass determined from analysis of the tube.

9.8 Analytical Precision

Demonstrate an analytical precision within ±20 percent using Equation 9.2. Analytical precision must be demonstrated during initial setup of this method and at least once per year. Calibration standard tubes may be used (see Section 10.0) and data from CCV may also be applied for this purpose.

$$\text{Analytical Precision} = \frac{(|A1 - A2|)}{\overline{A}} \times 100 \qquad \text{Eq. 9.2}$$

Where:

A1 = A measurement value taken from one spiked tube.

A2 = A measurement value taken from a second spiked tube.

$\overline{A}$ = The average of A1 and A2.

9.9 Field Replicate Precision

Use Equation 9.3 to determine and report replicate precision for duplicate field samples (see Section 9.4). The level of agreement between duplicate field samples is a measure of the precision achievable for the entire sampling and analysis procedure. Flag data sets for which the duplicate samples do not agree within 30 percent.

$$\text{Field Precision} = \frac{(|F1 - F2|)}{\overline{F}} \times 100 \qquad \text{Eq. 9.3}$$

Where:

F1 = A measurement value (mass) taken from one of the two field replicate tubes used in sampling.

F2 = A measurement value (mass) taken from the second of two field replicate tubes used in sampling.

$\overline{F}$ = The average of F1 and F2.

9.10 Desorption Efficiency and Compound Recovery

The efficiency of the thermal desorption method must be determined.

9.10.1 Quantitative (>95 percent) compound recovery must be demonstrated by repeat analyses on a same standard tube.

9.10.2 Compound recovery through the TD system can also be demonstrated by comparing the calibration check sample response factor obtained from direct GC injection of liquid standards with that obtained from thermal desorption analysis response factor using the same column under identical conditions.

9.10.3 If the relative response factors obtained for one or more target compounds introduced to the column via thermal desorption fail to meet the criteria in Section 9.10.1, you must adjust the TD parameters to meet the criteria and repeat the experiment. Once the thermal desorption conditions have been optimized, you must repeat this test each time the analytical system is recalibrated to demonstrate continued method performance.

9.11 Audit Samples

Certified reference standard samples must be used to audit this procedure (if available). Accuracy within 30 percent must be demonstrated for relevant ambient air concentrations (0.5 to 25 ppb).

9.12 Mass Spectrometer Tuning Criteria

Tune the mass spectrometer (if used) according to manufacturer's specifications. Verify the instrument performance by analyzing a 50 ηg injection of bromofluorobenzene. Prior to the beginning of each analytical sequence or every 24 hours during continuous GC/MS operation for this method demonstrate that the bromofluorobenzene tuning performance criteria in Table 9.1 have been met.

TABLE 9.1—GC/MS TUNING CRITERIA [1]

Target mass	Rel. to mass	Lower limit %	Upper limit %
50	95	8	40
75	95	30	66
95	95	100	100
96	95	5	9
173	174	0	2
174	95	50	120
175	174	4	9
176	174	93	101
177	176	5	9

[1] All ion abundances must be normalized to m/z 95, the nominal base peak, even though the ion abundance of m/z 174 may be up to 120 percent that of m/z 95.

9.13 Routine CCV at the Start of a Sequence

Run CCV before each sequence of analyses and after every tenth sample to ensure that the previous multi-level calibration (see Section 10.6.3) is still valid.

9.13.1 The sample concentration used for the CCV should be near the mid-point of the multi-level calibration range.

9.13.2 Quantitation software must be updated with response factors determined from the CCV standard. The percent deviation between the initial calibration and the CCV for all compounds must be within 30 percent.

9.14 CCV at the End of a Sequence

Run another CCV after running each sequence of samples. The initial CCV for a subsequent set of samples may be used as the final CCV for a previous analytical sequence, provided the same analytical method is used and the subsequent set of samples is analyzed immediately (within 4 hours) after the last CCV.

9.15 Additional Verification

Use a calibration check standard from a second, separate source to verify the original calibration at least once every three months.

9.16 Integration Method

Document the procedure used for integration of analytical data including field samples, calibration standards and blanks.

9.17 QC Records

Maintain all QC reports/records for each TD/GC/MS analytical system used for application of this method. Routine quality control requirements for this method are listed below and summarized in Table 17.1.

10.0 Calibration and Standardization

10.1 Calibrate the analytical system using standards covering the range of analyte masses expected from field samples.

10.2 Analytical results for field samples must fall within the calibrated range of the analytical system to be valid.

10.3 Calibration standard preparation must be fully traceable to primary standards of mass and/or volume, and/or be confirmed using an independent certified reference method.

10.3.1 Preparation of calibration standard tubes from standard atmospheres.

10.3.1.1 Subject to the requirements in Section 7.2.1, low-level standard atmospheres may be introduced to clean, conditioned sorbent tubes in order to produce calibration standards.

10.3.1.2 The standard atmosphere generator or system must be capable of producing sufficient flow at a constant rate to allow the required analyte mass to be introduced within a reasonable time frame and without affecting the concentration of the standard atmosphere itself.

10.3.1.3 The sampling manifold may be heated to minimize risk of condensation but the temperature of the gas delivered to the sorbent tubes may not exceed 100 °F.

10.3.1.4 The flow rates passed through the tube should be in the order of 50–100 mL/min and the volume of standard atmosphere sampled from the manifold or chamber must not exceed the breakthrough volume of the sorbent at the given temperature.

10.4 Preparation of calibration standard tubes from concentrated gas standards.

10.4.1 If a suitable concentrated gas standard (see Section 7.2.2) can be obtained, follow the manufacturer's recommendations relating to suitable storage conditions and product lifetime.

10.4.2 Introduce precise 0.5 to 500.0 mL aliquots of the standard to the sampling end of conditioned sorbent tubes in a 50–100 mL/min flow of pure carrier gas.

Note: This can be achieved by connecting the sampling end of the tube to an unheated GC injector (see Section 6.6) and introducing the aliquot of gas using a suitable gas syringe. Gas sample valves could alternatively be used to meter the standard gas volume.

10.4.3 Each sorbent tube should be left connected to the flow of gas for 2 minutes after standard introduction. As soon as each spiked tube is removed from the injection unit, seal it with long-term storage caps and place it in an appropriate tube storage/transportation container if it is not to be analyzed within 24 hours.

10.5 Preparation of calibration standard tubes from liquid standards.

10.5.1 Suitable standards are described in Section 7.3.

10.5.2 Introduce precise 0.5 to 2 µl aliquots of liquid standards to the sampling end of sorbent tubes in a flow (50–100 mL/min) of carrier gas using a precision syringe and an unheated injector (Section 6.5). The flow of gas should be sufficient to completely vaporize the liquid standard.

Note: If the analytes of interest are higher boiling than n-decane, reproducible analyte transfer to the sorbent bed is optimized by allowing the tip of the syringe to gently touch the sorbent retaining gauze at the sampling end of the tube.

10.5.3 Each sorbent tube is left connected to the flow of gas for 5 minutes after liquid standard introduction.

10.5.3.1 As soon as each spiked tube is removed from the injection unit, seal it with long-term storage caps and place it in an appropriate tube storage container if it is not to be analyzed within 24 hours.

Note: In cases where it is possible to selectively purge the solvent from the tube while all target analytes are quantitatively retained, a larger 2 µL injection may be made for optimum accuracy. However, if the solvent cannot be selectively purged and will be present during analysis, the injection volume should be as small as possible (*e.g.*, 0.5 µL) to minimize solvent interference.

Note: This standard preparation technique requires the entire liquid plug including the tip volume be brought into the syringe barrel. The volume in the barrel is recorded, the syringe is inserted into the septum of the spiking apparatus. The liquid is then quickly injected. Any remaining liquid in the syringe tip is brought back into the syringe barrel. The volume in the barrel is recorded and the amount spiked onto the tube is the difference between the before spiking volume and the after spiking volume. A bias occurs with this method when sample is drawn continuously up into the syringe to the specified volume and the calibration solution in the syringe tip is ignored.

10.6 Preparation of calibration standard tubes from multiple standards.

10.6.1 If it is not possible to prepare one standard containing all the compounds of interest (*e.g.,* because of chemical reactivity or the breadth of the volatility range), standard tubes can be prepared from multiple gas or liquid standards.

10.6.2 Follow the procedures described in Sections 10.4 and 10.5, respectively, for introducing each gas and/or liquid standard to the tube and load those containing the highest boiling compounds of interest first and the lightest species last.

10.7 Additional requirements for preparation of calibration tubes.

10.7.1 Storage of Calibration Standard Tubes

10.7.1.1 Seal tubes with long-term storage caps immediately after they have been disconnected from the standard loading manifold or injection apparatus.

10.7.1.2 Calibration standard tubes may be stored for no longer than 30 days and should be refrigerated if there is any risk of chemical interaction or degradation. Audit standards (see section 9.11) are exempt from this criteria and may be stored for the shelf-life specified on their certificates.

10.8 Keep records for calibration standard tubes to include the following:

10.8.1 The stock number of any commercial liquid or gas standards used.

10.8.2 A chromatogram of the most recent blank for each tube used as a calibration standard together with the associated analytical conditions and date of cleaning.

10.8.3 Date of standard loading.

10.8.4 List of standard components, approximate masses and associated confidence levels.

10.8.5 Example analysis of an identical standard with associated analytical conditions.

10.8.6 A brief description of the method used for standard preparation.

10.8.7 The standard's expiration date.

10.9 TD/GC/MS using standard tubes to calibrate system response.

10.9.1 Verify that the TD/GC/MS analytical system meets the instrument performance criteria given in Section 9.1.

10.9.2 The prepared calibration standard tubes must be analyzed using the analytical conditions applied to field samples (see Section 11.0) and must be selected to ensure quantitative transfer and adequate chromatographic resolution of target compounds, surrogates, and internal standards in order to enable reliable identification and quantitation of compounds of interest. The analytical conditions should also be sufficiently stringent to prevent buildup of higher boiling, non-target contaminants that may be collected on the tubes during field monitoring.

10.9.3 Calibration range. Each TD/GC/MS system must be calibrated at five concentrations that span the monitoring range of interest before being used for sample analysis. This initial multi-level calibration determines instrument sensitivity under the analytical conditions selected and the linearity of GC/MS response for the target compounds. One of the calibration points must be within a factor of five of the detection limit for the compounds of interest.

10.9.4 One of the calibration points from the initial calibration curve must be at the same concentration as the daily CCV standard (*e.g.,* the mass collected when sampling air at typical concentrations).

10.9.5 Calibration frequency. Each GC/MS system must be recalibrated with a full 5-point calibration curve following corrective action (*e.g.,* ion source cleaning or repair, column replacement) or if the instrument fails the daily calibration acceptance criteria.

10.9.5.1 CCV checks must be carried out on a regular routine basis as described in Section 9.14.

10.9.5.2 Quantitation ions for the target compounds are shown in Table 10.1. Use the primary ion unless interferences are present, in which case you should use a secondary ion.

TABLE 10.1—CLEAN AIR ACT VOLATILE ORGANIC COMPOUNDS FOR PASSIVE SORBENT SAMPLING

Compound	CAS No.	BP (°C)	Vapor pressure (mmHg) [a]	MW [b]	Characteristic ion(s)	
					Primary	Secondary
1,1-Dichloroethene	75–35–4	32	500	96.9	61	96
3-Chloropropene	107–05–1	44.5	340	76.5	76	41, 39, 78
1,1,2-Trichloro-1,2,2-trifluoroethane-1,1-Dichloroethane	75–34–3	57.0	230	99	63	65, 83, 85, 98, 100
1,2-Dichloroethane	107–06–2	83.5	61.5	99	62	98
1,1,1-Trichloroethane	71–55–6	74.1	100	133.4	97	99, 61
Benzene	71–43–2	80.1	76.0	78	78	
Carbon tetrachloride	56–23–5	76.7	90.0	153.8	117	119
1,2-Dichloropropane	78–87–5	97.0	42.0	113	63	112
Trichloroethene	79–01–6	87.0	20.0	131.4	95	97, 130, 132
1,1,2-Trichloroethane	79–00–5	114	19.0	133.4	83	97, 85
Toluene	108–88–3	111	22.0	92	92	91
Tetrachloroethene	127–18–4	121	14.0	165.8	164	129, 131, 166
Chlorobenzene	108–90–7	132	8.8	112.6	112	77, 114
Ethylbenzene	100–41–4	136	7.0	106	91	106
m,p-Xylene	108–38–3, 106–42–3	138	6.5	106.2	106	91
Styrene	100–42–5	145	6.6	104	104	78
o-Xylene	95–47–6	144	5.0	106.2	106	91
p-Dichlorobenzene	106–46–7	173	0.60	147	146	111, 148

[a] Pressure in millimeters of mercury.

[b] Molecular weight.

11.0 Analytical Procedure

11.1 Preparation for Sample Analysis

11.1.1 Each sequence of analyses must be ordered as follows:

11.1.1.1 CCV.
11.1.1.2 A laboratory blank.
11.1.1.3 Field blank.
11.1.1.4 Sample(s).
11.1.1.5 Field blank.
11.1.1.6 CCV after 10 field samples.
11.1.1.7 CCV at the end of the sample batch.

11.2 Pre-desorption System Checks and Procedures

11.2.1 Ensure all sample tubes and field blanks are at ambient temperature before removing them from the storage container.

11.2.2 If using an automated TD/GC/MS analyzer, remove the long-term storage caps from the tubes, replace them with appropriate analytical caps, and load them into the system in the sequence described in Section 11.1. Alternatively, if using a manual system, uncap and analyze each tube, one at a time, in the sequence described in Section 11.1.

11.2.3 The following thermal desorption system integrity checks and procedures are required before each tube is analyzed.

Note: Commercial thermal desorbers should implement these steps automatically.

11.2.3.1 Tube leak test: Each tube must be leak tested as soon as it is loaded into the carrier gas flow path before analysis to ensure data integrity.

11.2.3.2 Conduct the leak test at the GC carrier gas pressure, without heat or gas flow applied. Tubes that fail the leak test should not be analyzed, but should be resealed and stored intact. On automated systems, the instrument should continue to leak test and analyze subsequent tubes after a given tube has failed. Automated systems must also store and record which tubes in a sequence have failed the leak test. Information on failed tubes should be downloaded with the batch of sequence information from the analytical system.

11.2.3.3 Leak test the sample flow path. Leak check the sample flow path of the thermal desorber before each analysis without heat or gas flow applied to the sample tube. Stop the automatic sequence of tube desorption and GC analysis if any leak is detected in the main sample flow path. This process may be carried out as a separate step or as part of Section 11.2.3.2.

11.2.4 Optional Dry Purge

11.2.4.1 Tubes may be dry purged with a flow of pure dry gas passing into the tube from the sampling end, to remove water vapor and other very volatile interferents if required.

11.2.5 Internal Standard (IS) Addition

11.2.5.1 Use the internal standard addition function of the automated thermal desorber (if available) to introduce a precise aliquot of the internal standard to the sampling end of each tube after the leak test and shortly before primary (tube) desorption).

Note: This step can be combined with dry purging the tube (Section 11.2.4) if required.

11.2.5.2 If the analyzer does not have a facility for automatic IS addition, gas or liquid internal standard can be manually introduced to the sampling end of tubes in a flow of carrier gas using the types of procedure described in Sections 10.3 and 10.4, respectively.

11.2.6 Pre-purge. Each tube should be purged to vent with carrier gas flowing in the desorption direction (*i.e.,* flowing into the tube from the non-sampling end) to remove oxygen before heat is applied. This is to prevent analyte and sorbent oxidation and to prevent deterioration of key analyzer components such as the GC column and mass spectrometer (if applicable). A series of schematics illustrating these steps is presented in Figures 17.2 and 17.3.

11.3 Analytical Procedure

11.3.1 Steps Required for Thermal Desorption

11.3.1.1 Ensure that the pressure and purity of purge and carrier gases supplying the TD/GC/MS system, meet manufacturer specifications and the requirements of this method.

11.3.1.2 Ensure also that the analytical method selected meets the QC requirements of this method (Section 9) and that all the analytical parameters are at set point.

11.3.1.3 Conduct predesorption system checks (see Section 11.2).

11.3.1.4 Desorb the sorbent tube under conditions demonstrated to achieve >95 percent recovery of target compounds (see Section 9.5.2).

Note: Typical tube desorption conditions range from 280–350 °C for 5–15 minutes with a carrier gas flow of 30–100 mL/min passing through the tube from the non-sampling end such that analytes are flushed out of the tube from the sampling end. Desorbed VOCs are concentrated (refocused) on a secondary, cooled sorbent trap integrated into the analytical equipment (see Figure 17.4). The focusing trap is typically maintained at a temperature between −30 and +30 °C during focusing. Selection of hydrophobic sorbents for focusing and setting a trapping temperature of +25 to 27 °C aid analysis of humid samples because these settings allow selective elimination of any residual water from the system, prior to GC/MS analysis.

Note: The transfer of analytes from the tube to the focusing trap during primary (tube) desorption can be carried out splitless or under controlled split conditions (see Figure 17.4) depending on the masses of target compounds sampled and the requirements of the system—sensitivity, required calibration range, column overload limitations, etc. Instrument controlled sample splits must be demonstrated by showing the reproducibility using calibration standards. Field and laboratory blank samples must be analyzed at the same split as the lowest calibration standard. During secondary (trap) desorption the focusing trap is heated rapidly (typically at rates >40 °C/s) with inert (carrier) gas flowing through the trap (3–100 mL/min) in the reverse direction to that used during focusing.

11.3.1.5 The split conditions selected for optimum field sample analysis must also be demonstrated on representative standards.

Note: Typical trap desorption temperatures are in the range 250–360 °C, with a ''hold'' time of 1–3 minutes at the highest temperature. Trap desorption automatically triggers the start of GC analysis. The trap desorption can also be carried out under splitless conditions (*i.e.*, with everything desorbed from the trap being transferred to the analytical column and GC detector) or, more commonly, under controlled split conditions (see Figure 17.4). The selected split ratio depends on the masses of target compounds sampled and the requirements of the system—sensitivity, required calibration range, column overload limitations, etc. If a split is selected during both primary (trap) desorption and secondary (trap) desorption, the overall split ratio is the product of the two. Such 'double' split capability gives optimum flexibility for accommodating concentrated samples as well as trace-level samples on the TD/GC/MS analytical system. High resolution capillary columns and most GC/MS detectors tend to work best with approximately 20–200 ng per compound per tube to avoid saturation. The overall split ratio must be adjusted such that, when it is applied to the sample mass that is expected to be collected during field monitoring, the amount reaching the column will be attenuated to fall within this range. As a rule of thumb this means that ~20 ng samples will require splitless or very low split analysis, ~2 µg samples will require a split ratio in the order of ~50:1 and 200 µg samples will require a double split method with an overall split ratio in the order of 2,000:1.

11.3.1.6 Analyzed tubes must be resealed with long-term storage caps immediately after analysis (manual systems) or after completion of a sequence (automated systems). This prevents contamination, minimizing the extent of tube reconditioning required before subsequent reuse.

11.3.2 GC/MS Analytical Procedure

11.3.2.1 Heat/cool the GC oven to its starting set point.

11.3.2.2 If using a GC/MS system, it can be operated in either MS-Scan or MS–SIM mode (depending on required sensitivity levels and the type of mass spectrometer selected). As soon as trap desorption and transfer of analytes into the GC column triggers the start of the GC/MS analysis, collect mass spectral data over a range of masses from 35 to 300 amu. Collect at least 10 data points per eluting chromatographic peak in order to adequately integrate and quantify target compounds.

11.3.2.3 Use secondary ion quantitation only when there are sample matrix interferences with the primary ion. If secondary ion quantitation is performed, flag the data and document the reasons for the alternative quantitation procedure.

11.3.2.4 Data reduction is performed by the instruments post processing program that is automatically accessed after data acquisition is completed at the end of the GC run. The concentration of each target compound is calculated using the previously established response factors for the CCV analyzed in Section 11.1.1.6.

11.3.2.5 Whenever the thermal desorption—GC/MS analytical method is changed or major equipment maintenance is performed, you must conduct a new five-level calibration (see Section 10.6.3). System calibration remains valid as long as results from subsequent CCV are within 30 percent of the most recent 5-point calibration (see Section 10.9.5). Include relevant CCV data in the supporting information in the data report for each set of samples.

11.3.2.6 Document, flag and explain all sample results that exceed the calibration range. Report flags and provide documentation in the analytical results for the affected sample(s).

12.0 Data Analysis, Calculations, and Reporting

12.1 Recordkeeping Procedures for Sorbent Tubes

12.1.1 Label sample tubes with a unique identification number as described in Section 6.3.

12.1.2 Keep records of the tube numbers and sorbent lots used for each sampling period.

12.1.3 Keep records of sorbent tube packing if tubes are manually prepared in the laboratory and not supplied commercially. These records must include the masses and/or bed lengths of sorbent(s) contained in each tube, the maximum allowable temperature for that tube and the date each tube was packed. If a tube is repacked at any stage, record the date of tube repacking and any other relevant information required in Section 12.1.

12.1.4 Keep records of the conditioning and blanking of tubes. These records must include, but are not limited to, the unique identification number and measured background resulting from the tube conditioning.

12.1.5 Record the location, dates, tube identification and times associated with each sample collection. Record this information on a Chain of Custody form that is sent to the analytical laboratory.

12.1.6 Field sampling personnel must complete and send a Chain of Custody to the analysis laboratory (see Section 8.6.4 of Method 325A for what information to include and Section 17.0 of this method for an example form). Duplicate copies of the Chain of Custody must be included with the sample report and stored with the field test data archive.

12.1.7 Field sampling personnel must also keep records of the unit vector wind direction, sigma theta, temperature and barometric pressure averages for the sampling period. See Section 8.3.4 of Method 325A.

12.1.8 Laboratory personnel must record the sample receipt date, and analysis date.

12.1.9 Laboratory personnel must maintain records of the analytical method and sample results in electronic or hardcopy in sufficient detail to reconstruct the calibration, sample, and quality control results from each sampling period.

12.2 Calculations

12.2.1 Complete the calculations in this section to determine compliance with calibration quality control criteria (see also Table 17.1).

12.2.1.1 Response factor (RF). Calculate the RF using Equation 12.1:

$$RF = \frac{[A_s \times M_{is}]}{[A_{is} \times M_s]} \qquad \text{Eq. 12.1}$$

Where:

A_s = Peak area for the characteristic ion of the analyte.

A_{is} = Peak area for the characteristic ion of the internal standard.

M_s = Mass of the analyte.

M_{is} = Mass of the internal standard.

12.2.1.2 Standard deviation of the response factors (SD_{RF}). Calculate the SDRF using Equation 12.2:

$$SD_{RF} = \sqrt{\frac{\sum_{i=1}^{n}\left(RF_i - \overline{RF}\right)^2}{(n-1)}} \qquad \text{Eq. 12.2}$$

Where:

RF_i = RF for each of the calibration compounds.

$\overline{RF}$ = Mean RF for each compound from the initial calibration.

n = Number of calibration standards.

12.2.1.3 Percent deviation (%DEV). Calculate the %DEV using Equation 12.3:

$$\%DEV = SD_{RF} \div \overline{RF} \times 100 \qquad \text{Eq. 12.3}$$

Where:

SD_{RF} = Standard deviation.

$\overline{RF}$ = Mean RF for each compound from the initial calibration.

12.2.1.4 Relative percent difference (RPD). Calculate the RPD using Equation 12.4:

$$RPD = \frac{R1 - R2}{[(R1 + R2)/2]} \times 100 \qquad \text{Eq. 12.4}$$

Where:

R1, R2 = Values that are being compared (*i.e.,* response factors in CCV).

12.2.2 Determine the equivalent concentration of compounds in atmospheres as follows.

12.2.3 Correct target concentrations determined at the sampling site temperature and atmospheric pressure to standard conditions (25 °C and 760 mm mercury) using Equation 12.5 (Reference 21).

$$U_{NTP} = U \times \left(\frac{298.2}{t_{ss}}\right)^{\frac{3}{2}} \times \left(\frac{P_{ss}}{760}\right) \qquad \text{Eq. 12.5}$$

Where:

t_{ss} = The average temperature during the collection period at the sampling site (K).

P_{ss} = The average pressure at the sampling site during the collection period (mm Hg).

U = The diffusive uptake rate (sampling rate) (mL/min).

12.2.4 For passive sorbent tube samples, calculate the concentration of the target compound(s) in the sampled air, in µg/m^3 by using Equation 12.6 (Reference 22).

$$C_m = \frac{m_{meas}}{U_{NTP} \times t} \times 10^6 \qquad \text{Eq. 12.6}$$

Where:

C_m = The concentration of target compound in the air sampled (µg/m^3).

m_{meas} = The mass of the compound as measured in the sorbent tube (µg).

U_{NTP} = The diffusive uptake rate corrected for local conditions (sampling rate) (mL/min).

t = The exposure time (minutes).

Note: Diffusive uptake rates for common VOCs, using carbon sorbents packed into sorbent tubes of the dimensions specified in Section 6.1, are listed in Table 12.1. Adjust analytical conditions to keep expected sampled masses within range (see Sections 11.3.1.3 to 11.3.1.5). Best possible method detection limits are typically in the order of 0.1 ppb for 1,3-butadiene and 0.05 ppb for volatile aromatics such as benzene for 14-day monitoring. However, actual detection limits will depend upon the analytical conditions selected.

TABLE 12.1—VALIDATED SORBENTS AND UPTAKE RATES (mL/MIN) FOR SELECTED CLEAN AIR ACT COMPOUNDS

Compound	Carbopack™ X[a]	Carbograph™1 TD	Carbopack™ B
1,1-Dichloroethene	0.57 ± 0.14	not available	not available.
3-Chloropropene	0.51 ± 0.3	not available	not available.
1,1-Dichloroethane	0.57 ± 0.1	not available	not available.
1,2-Dichloroethane	0.57 ± 0.08	not available	not available.
1,1,1-Trichloroethane	0.51 ± 0.1	not available	not available.
Benzene	0.67 ± 0.06	0.63 ± 0.07[b]	0.63 ± 0.07[b].
Carbon tetrachloride	0.51 ± 0.06	not available	not available.
1,2-Dichloropropane	0.52 ± 0.1	not available	not available.
Trichloroethene	0.5 ± 0.05	not available	not available.
1,1,2-Trichloroethane	0.49 ± 0.13	not available	not available.
Toluene	0.52 ± 0.14	0.56 ± 0.06[c]	0.56 ± 0.06[c].
Tetrachloroethene	0.48 ± 0.05	not available	not available.
Chlorobenzene	0.51 ± 0.06	not available	not available.
Ethylbenzene	0.46 ± 0.07	not available	0.50[c].
m,p-Xylene	0.46 ± 0.09	0.47 ± 0.04[c]	0.47 ± 0.04[c].
Styrene	0.5 ± 0.14	not available	not available.
o-Xylene	0.46 ± 0.12	0.47 ± 0.04[c]	0.47 ± 0.04[c].
p-Dichlorobenzene	0.45 ± 0.05	not available	not available.

[a] Reference 3, McClenny, J. Environ. Monit. 7:248–256. Based on 24-hour duration.

[b] Reference 24, BS EN 14662–4:2005 (incorporated by reference—see § 63.14). Based on 14-day duration.

[c] Reference 25, ISO 16017–2:2003(E) (incorporated by reference—see § 63.14). Based on 14-day duration.

13.0 Method Performance

The performance of this procedure for VOC not listed in Table 12.1 is determined using the procedure in Addendum A of this Method or by one of the following national/international standard methods: ISO 16017–2:2003(E), ASTM D6196–03 (Reapproved 2009), or BS EN 14662–4:2005 (all incorporated by reference—see § 63.14).

13.1 The valid range for measurement of VOC is approximately 0.5 µg/m^3 to 5 mg/m^3 in air, collected over a 14-day sampling period. The upper limit of the useful range depends on the split ratio selected (Section 11.3.1) and the dynamic range of the analytical system. The lower limit of the useful range depends on the noise from the analytical instrument detector and on the blank level of target compounds or interfering compounds on the sorbent tube (see Section 13.3).

13.2 Diffusive sorbent tubes compatible with passive sampling and thermal desorption methods have been evaluated at relatively high atmospheric concentrations (*i.e.*, mid-ppb to ppm) and published for use in workplace air and industrial/mobile source emissions (References 15–16, 21–22).

13.3 Best possible detection limits and maximum quantifiable concentrations of air pollutants range from sub-part-per-trillion (sub-ppt) for halogenated species such as CCl4 and the freons using an electron capture detector (ECD), SIM Mode GC/MS, triple quad MS or GC/TOF MS to sub-ppb for volatile hydrocarbons collected over 72 hours followed by analysis using GC with quadrupole MS operated in the full SCAN mode.

13.3.1 Actual detection limits for atmospheric monitoring vary depending on several key factors. These factors are:

- Minimum artifact levels.
- GC detector selection.
- Time of exposure for passive sorbent tubes.
- Selected analytical conditions, particularly column resolution and split ratio.

14.0 Pollution Prevention

This method involves the use of ambient concentrations of gaseous compounds that post little or no danger of pollution to the environment.

15.0 Waste Management

Dispose of expired calibration solutions as hazardous materials. Exercise standard laboratory environmental practices to minimize the use and disposal of laboratory solvents.

16.0 References

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13. MDHS 40 (Toluene in air), ‘‘Laboratory Method Using Pumped Porous Polymer Adsorbent Tubes, Thermal Desorption and Gas Chromatography,’’ Method for the Determination of Hazardous Substances (MDHS), UK Health and Safety Executive, Sheffield, UK.
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17.0 Tables, Diagrams, Flowcharts and Validation Data

TABLE 17.1—SUMMARY OF GC/MS ANALYSIS QUALITY CONTROL PROCEDURES

Parameter	Frequency	Acceptance criteria	Corrective action
Bromofluorobenzene Instrument Tune Performance Check.	Daily[a] prior to sample analysis	Evaluation criteria presented in Section 9.5 and Table 9.2.	(1) Retune and or (2) Perform Maintenance.
Five point calibration bracketing the expected sample concentration.	Following any major change, repair or maintenance or if daily CCV does not meet method requirements. Recalibration not to exceed three months.	(1) Percent Deviation (%DEV) of response factors ±30%. (2) Relative Retention Times (RRTs) for target peaks ±0.06 units from mean RRT.	(1) Repeat calibration sample analysis. (2) Repeat linearity check. (3) Prepare new calibration standards as necessary and repeat analysis.
Calibration Verification (CCV Second source calibration verification check).	Following the calibration curve	The response factor ±30% DEV from calibration curve average response factor.	(1) Repeat calibration check. (2) Repeat calibration curve.
Laboratory Blank Analysis	Daily[a] following bromofluoro- benzene and calibration check; prior to sample analysis.	(1) ≤0.2 ppbv per analyte or ≤3 times the LOD, whichever is greater. (2) Internal Standard (IS) area response ±40% and IS Retention Time (RT) ±0.33 min. of most recent calibration check.	(1) Repeat analysis with new blank tube. (2) Check system for leaks, contamination. 3) Analyze additional blank.
Blank Sorbent Tube Certification	One tube analyzed for each batch of tubes cleaned or 10 percent of tubes whichever is greater.	<0.2 ppbv per VOC targeted compound or 3 times the LOD, whichever is greater.	Reclean all tubes in batch and reanalyze.
Samples—Internal Standards	All samples	IS area response ±40% and IS RT ±0.33 min. of most recent calibration validation.	Flag Data for possible invalidation.

[a] Every 24 hours.

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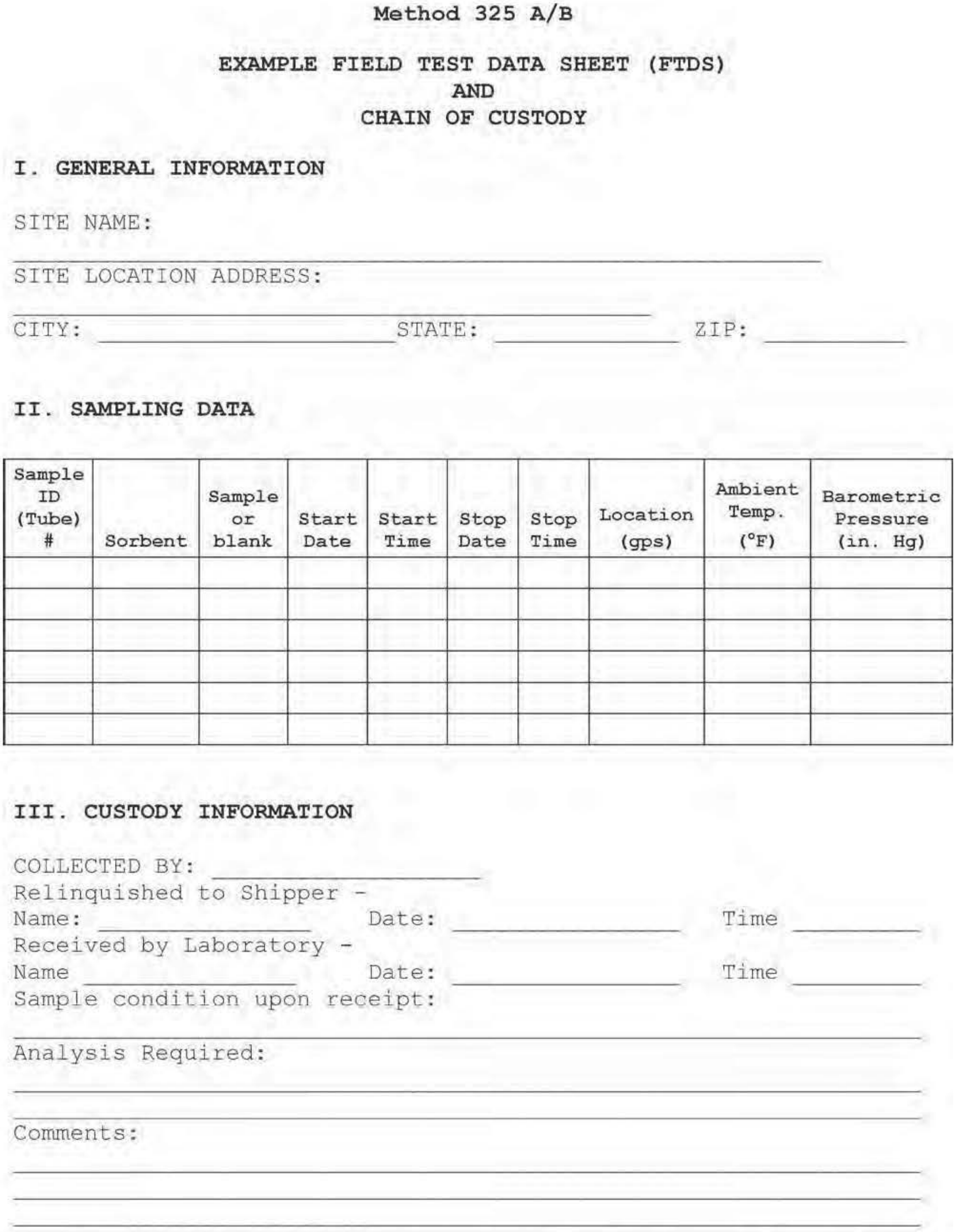

Method 325 A/B

EXAMPLE FIELD TEST DATA SHEET (FTDS)
AND
CHAIN OF CUSTODY

I. GENERAL INFORMATION

SITE NAME: ______________________________

SITE LOCATION ADDRESS: ______________________________

CITY: ______________ STATE: __________ ZIP: ________

II. SAMPLING DATA

Sample ID (Tube) #	Sorbent	Sample or blank	Start Date	Start Time	Stop Date	Stop Time	Location (gps)	Ambient Temp. (°F)	Barometric Pressure (in. Hg)

III. CUSTODY INFORMATION

COLLECTED BY: ______________

Relinquished to Shipper -

Name: __________ Date: ____________ Time ________

Received by Laboratory -

Name __________ Date: ____________ Time ________

Sample condition upon receipt:

____

Analysis Required:

____

____

Comments:

____

____

____

Figure 17.1. Example Field Data From and Chain of Custody

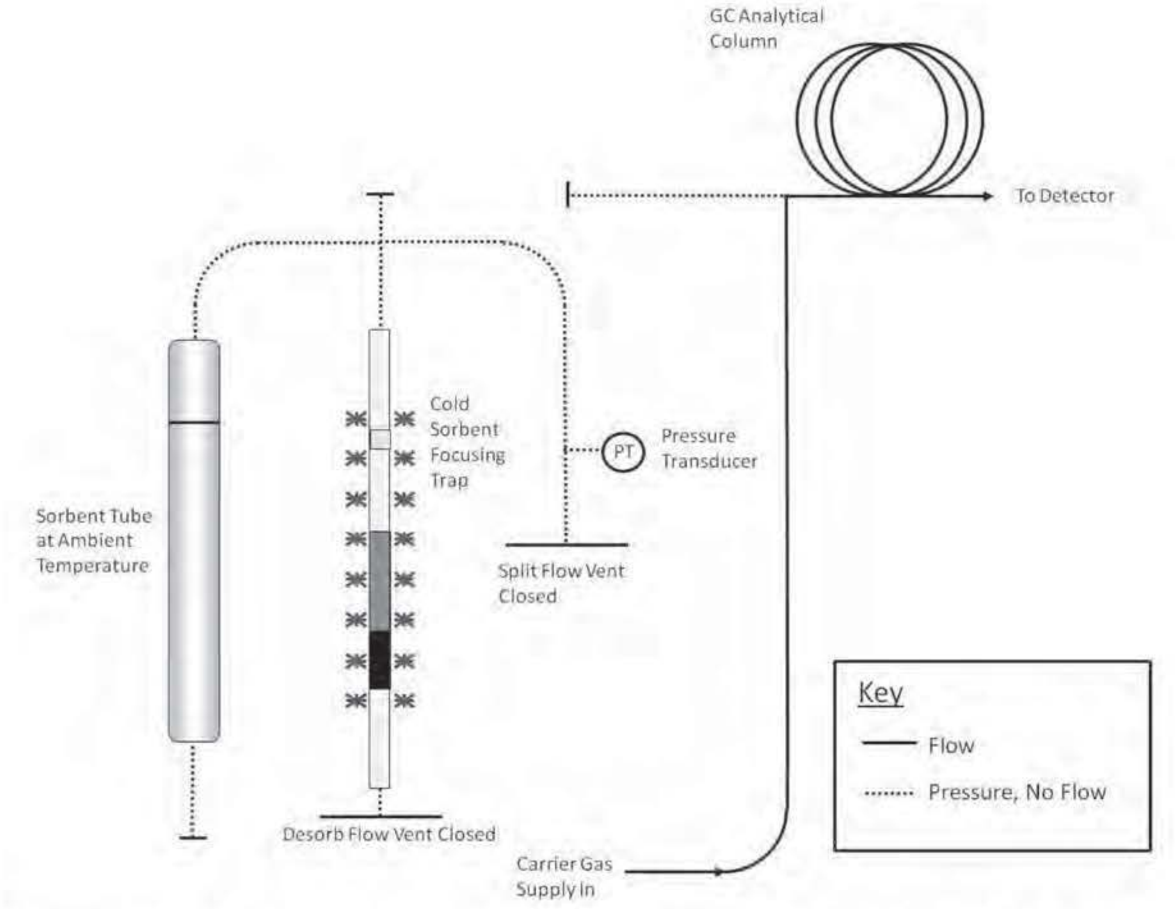

Figure 17.2. Schematic of Thermal Desorption Flow Path During Leak Testing

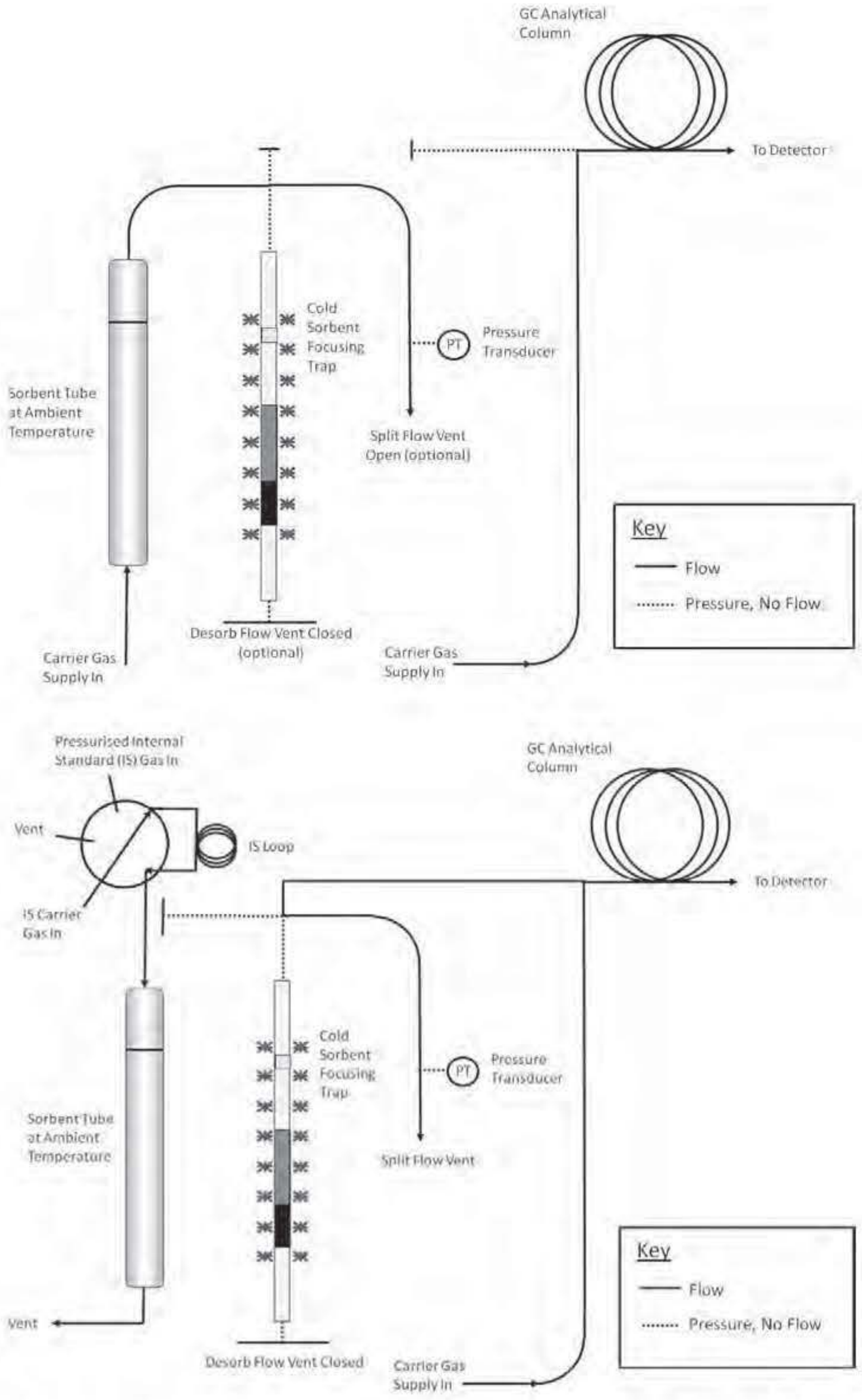

Figure 17.3. Schematic of Thermal Desorption Flow During Purge of Air (Top) and Addition of IS Gas to the Sorbent Tube (Bottom)

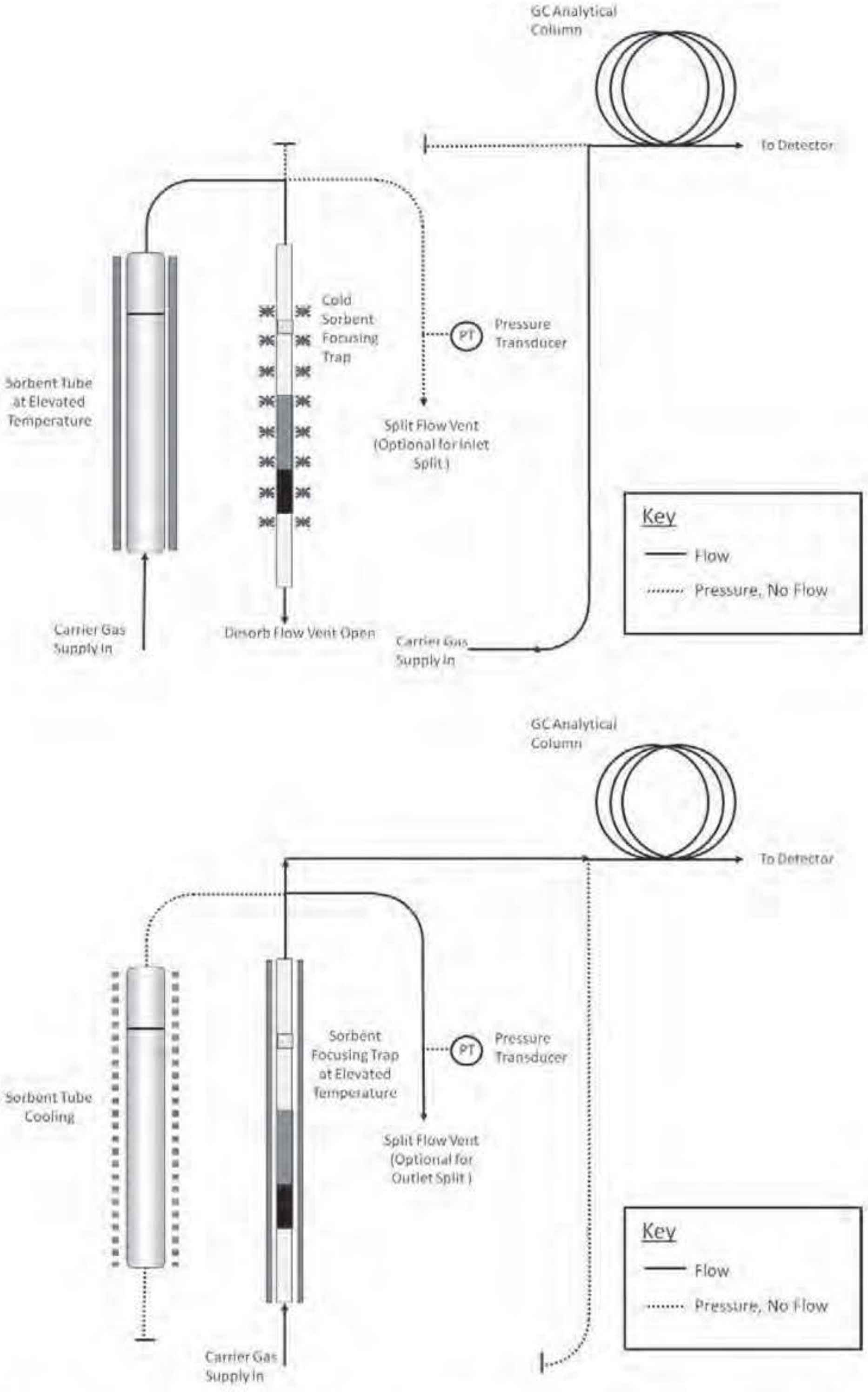

Figure 17.4. Schematic of Thermal Desorption Flow Path During Primary (Tube) Desorption (Top) and Secondary (Trap) Desorption and Transfer to the GC (Bottom)

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ADDENDUM A to Method 325B—Method 325 Performance Evaluation

A.1 Scope and Application

A.1.1 To be measured by Methods 325A and 325B, each new target volatile organic compound (VOC) or sorbent that is not listed in Table 12.1 must be evaluated by exposing the selected sorbent tube to a known concentration of the target compound(s) in an exposure chamber following the procedure in this Addendum or by following the procedures in the national/international standard methods: ISO 16017–2:2003(E), ASTM D6196–03 (Reapproved 2009), or BS EN 14662–4:2005 (all incorporated by reference—see § 63.14), or reported in peer-reviewed open literature.

A.1.2 You must determine the uptake rate and the relative standard deviation compared to the theoretical concentration of volatile material in the exposure chamber for each of the tests required in this method. If data that meet the requirement of this Addendum are available in the peer reviewed open literature for VOCs of interest collected on your passive sorbent tube configuration, then such data may be submitted in lieu of the testing required in this Addendum.

A.1.3 You must expose sorbent tubes in a test chamber to parts per trillion by volume (pptv) and low parts per billion by volume (ppbv) concentrations of VOCs in humid atmospheres to determine the sorbent tube uptake rate and to confirm compound capture and recovery.

A.2 Summary of Method

Note: The technique described here is one approach for determining uptake rates for new sorbent/sorbate pairs. It is equally valid to follow the techniques described in any one of the following national/international standards methods: ISO 16017–2:2003(E), ASTM D6196–03 (Reapproved 2009), or BS EN 14662–4:2005 (all incorporated by reference—see § 63.14).

A.2.1 Known concentrations of VOC are metered into an exposure chamber containing sorbent tubes filled with media selected to capture the volatile organic compounds of interest (see Figure A.1 and A.2 for an example of the exposure chamber and sorbent tube retaining rack). VOC are diluted with humid air and the chamber is allowed to equilibrate for 6 hours. Clean passive sampling devices are placed into the chamber and exposed for a measured period of time. The passive uptake rate of the passive sampling devices is determined using the standard and dilution gas flow rates. Chamber concentrations are confirmed with whole gas sample collection and analysis or direct interface volatile organic compound measurement methods.

A.2.2 An exposure chamber and known gas concentrations must be used to challenge and evaluate the collection and recovery of target compounds from the sorbent and tube selected to perform passive measurements of VOC in atmospheres.

A.3 Definitions

A.3.1 *cc* is cubic centimeter.

A.3.2 *ECD* is electron capture detector.

A.3.3 *FID* is flame ionization detector.

A.3.4 *LED* is light-emitting diode.

A.3.5 *MFC* is mass flow controller.

A.3.6 *MFM* is mass flow meter.

A.3.7 *min* is minute.

A.3.8 *ppbv* is parts per billion by volume.

A.3.9 *ppmv* is parts per million by volume.

A.3.10 *PSD* is passive sampling device.

A.3.11 *psig* is pounds per square inch gauge.

A.3.12 *RH* is relative humidity.

A.3.13 *VOC* is volatile organic compound.

A.4 Interferences

A.4.1 VOC contaminants in water can contribute interference or bias results high. Use only distilled, organic-free water for dilution gas humidification.

A.4.2 Solvents and other VOC-containing liquids can contaminate the exposure chamber. Store and use solvents and other VOC-containing liquids in the exhaust hood when exposure experiments are in progress to prevent the possibility of contamination of VOCs into the chamber through the chamber's exhaust vent.

Note: Whenever possible, passive sorbent evaluation should be performed in a VOC free laboratory.

A.4.3 PSDs should be handled by personnel wearing only clean, white cotton or powder free nitrile gloves to prevent contamination of the PSDs with oils from the hands.

A.4.4 This performance evaluation procedure is applicable to only volatile materials that can be measured accurately with direct interface gas chromatography or whole gas sample collection, concentration and analysis. Alternative methods to confirm the concentration of volatile materials in exposure chambers are subject to Administrator approval.

A.5 Safety

A.5.1 This procedure does not address all of the safety concerns associated with its use. It is the responsibility of the user of this standard to establish appropriate field and laboratory safety and health practices and determine the applicability of regulatory limitations prior to use.

A.5.2 Laboratory analysts must exercise appropriate care in working with high-pressure gas cylinders.

A.6 Equipment and Supplies

A.6.1 You must use an exposure chamber of sufficient size to simultaneously expose a minimum of eight sorbent tubes.

A.6.2 Your exposure chamber must not contain VOC that interfere with the compound under evaluation. Chambers made of glass and/or stainless steel have been used successfully for measurement of known concentration of selected VOC compounds.

A.6.3 The following equipment and supplies are needed:

- Clean, white cotton or nitrile gloves;
- Conditioned passive sampling device tubes and diffusion caps; and
- NIST traceable high resolution digital gas mass flow meters (MFMs) or flow controllers (MFCs).

A.7 Reagents and Standards

A.7.1 You must generate an exposure gas that contains between 35 and 75 percent relative humidity and a concentration of target compound(s) within 2 to 5 times the concentration to be measured in the field.

A.7.2 Target gas concentrations must be generated with certified gas standards and diluted with humid clean air. Dilution to reach the desired concentration must be done with zero grade air or better.

A.7.3 The following reagents and standards are needed:

- Distilled water for the humidification;
- VOC standards mixtures in high-pressure cylinder certified by the supplier (**Note:** The accuracy of the certified standards has a direct bearing on the accuracy of the measurement results. Typical vendor accuracy is ±5 percent accuracy but some VOC may only be available at lower accuracy (*e.g.*, acrolein at 10 percent)); and
- Purified dilution air containing less than 0.2 ppbv of the target VOC.

A.8 Sample Collection, Preservation and Storage

A.8.1 You must use certified gas standards diluted with humid air. Generate humidified air by adding distilled organic free water to purified or zero grade air. Humidification may be accomplished by quantitative addition of water to the air dilution gas stream in a heated chamber or by passing purified air through a humidifying bubbler. You must control the relative humidity in the test gas throughout the period of passive sampler exposure.

Note: The RH in the exposure chamber is directly proportional to the fraction of the purified air that passes through the water in the bubbler before entering the exposure chamber. Achieving uniform humidification in the proper range is a trial-and-error process with a humidifying bubbler. You may need to heat the bubbler to achieve sufficient humidity. An equilibration period of approximately 15 minutes is required following each adjustment of the air flow through the humidifier. Several adjustments or equilibration cycles may be required to achieve the desired RH level.

Note: You will need to determine both the dilution rate and the humidification rate for your design of the exposure chamber by trial and error before performing method evaluation tests.

A.8.2 Prepare and condition sorbent tubes following the procedures in Method 325B Section 7.0.

A.8.3 You must verify that the exposure chamber does not leak.

A.8.4 You must complete two evaluation tests using a minimum of eight passive sampling tubes in each test with less than 5-percent depletion of test analyte by the samplers.

A.8.4.1 Perform at least one evaluation at two to five times the estimated analytical detection limit or less.

A.8.4.2 Perform second evaluation at a concentration equivalent to the middle of the analysis calibration range.

A.8.5 You must evaluate the samplers in the test chamber operating between 35 percent and 75 percent RH, and at 25 ± 5 °C. Allow the exposure chamber to equilibrate for 6 hours before starting an evaluation.

A.8.6 The flow rate through the chamber must be ≤0.5 meter per second face velocity across the sampler face.

A.8.7 Place clean, ready to use sorbent tubes into the exposure chamber for predetermined amounts of time to evaluate collection and recovery from the tubes. The exposure time depends on the concentration of volatile test material in the chamber and the detection limit required for the sorbent tube sampling application. Exposure time should match sample collection time. The sorbent tube exposure chamber time may not be less than 24 hours and should not be longer than 2 weeks.

A.8.7.1 To start the exposure, place the clean PSDs equipped with diffusion caps on the tube inlet into a retaining rack.

A.8.7.2 Place the entire retaining rack inside the exposure chamber with the diffusive sampling end of the tubes facing into the chamber flow. Seal the chamber and record the exposure start time, chamber RH, chamber temperature, PSD types and numbers, orientation of PSDs, and volatile material mixture composition (see Figure A.2).

A.8.7.3 Diluted, humidified target gas must be continuously fed into the exposure chamber during cartridge exposure. Measure the flow rate of target compound standard gas and dilution air to an accuracy of 5 percent.

A.8.7.4 Record the time, temperature, and RH at the beginning, middle, and end of the exposure time.

A.8.7.5 At the end of the exposure time, remove the PSDs from the exposure chamber. Record the exposure end time, chamber RH, and temperature.

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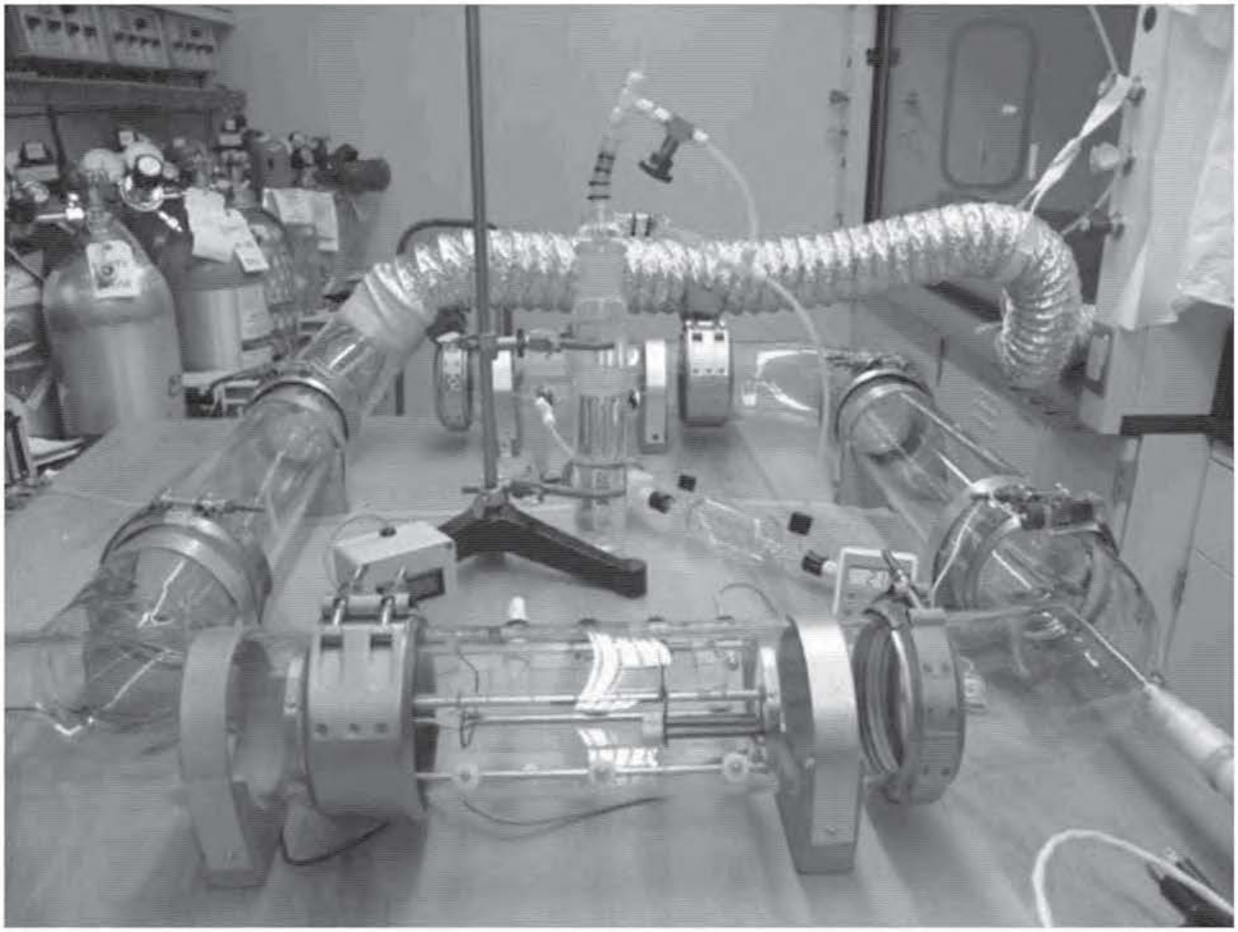
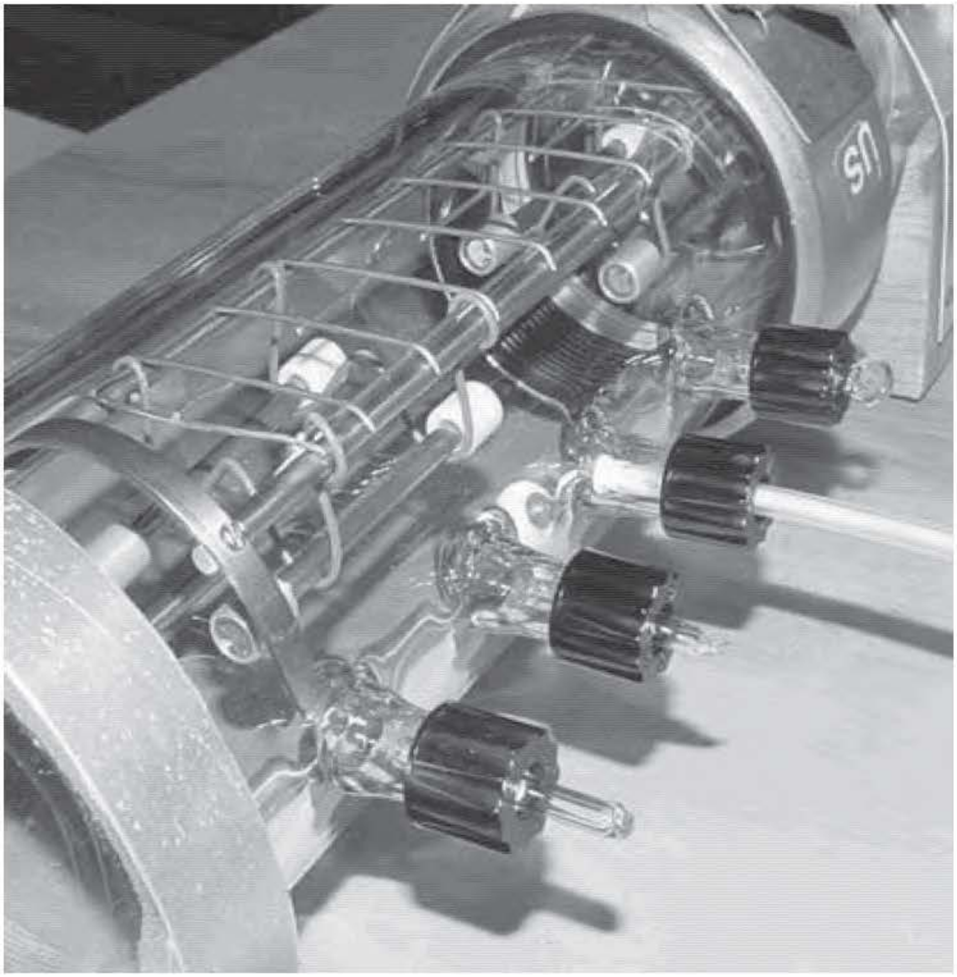


Figure A.1. Example Sorbent Tube Exposure Chamber



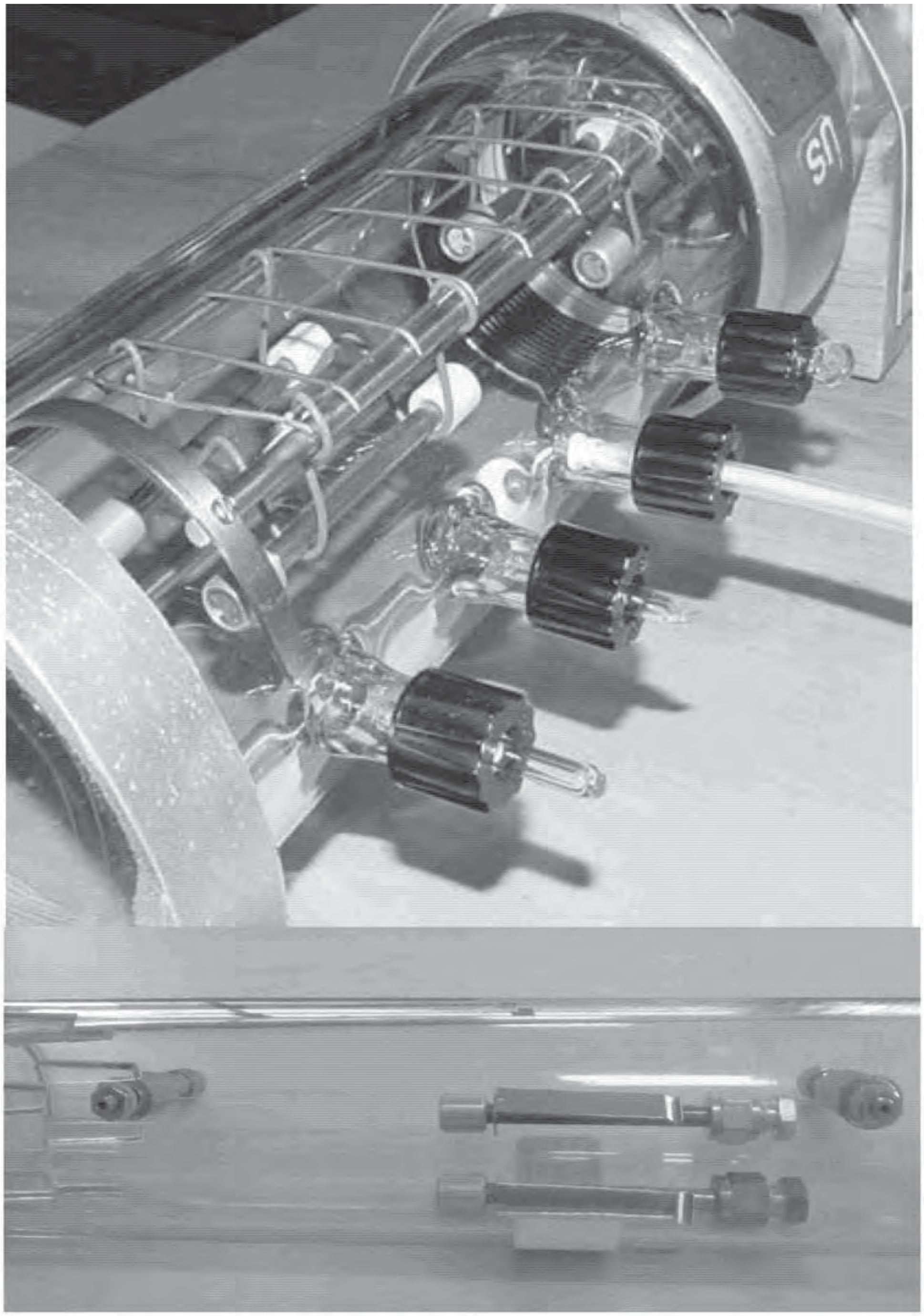


Figure A.2. Example Tube Retaining Rack in Exposure Chamber

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A.9 Quality Control

A.9.1 Monitor and record the exposure chamber temperature and RH during PSD exposures.

A.9.2 Measure the flow rates of standards and purified humified air immediately following PSD exposures.

A.10 Calibration and Standardization

A.10.1 Follow the procedures described in Method 325B Section 10.0 for calibration.

A.10.2 Verify chamber concentration by direct injection into a gas chromatograph calibrated for the target compound(s) or by collection of an integrated SUMMA canister followed by analysis using a preconcentration gas chromatographic method such as EPA Compendium Method TO–15, Determination of VOCs in Air Collected in Specially-Prepared Canisters and Analyzed By GC/MS.

A.10.2.1 To use direct injection gas chromatography to verify the exposure chamber concentration, follow the procedures in Method 18 of 40 CFR part 60, Appendix A–6. The method ASTM D6420–99 (Reapproved 2010) (incorporated by reference—see § 63.14) is an acceptable alternative to EPA Method 18 of 40 CFR part 60).

Note: Direct injection gas chromatography may not be sufficiently sensitive for all compounds. Therefore, the whole gas preconcentration sample and analysis method may be required to measure at low concentrations.

A.10.2.2 To verify exposure chamber concentrations using SUMMA canisters, prepare clean canister(s) and measure the concentration of VOC collected in an integrated SUMMA canister over the period used for the evaluation (minimum 24 hours). Analyze the TO–15 canister sample following EPA Compendium Method TO–15.

A.10.2.3 Compare the theoretical concentration of volatile material added to the test chamber to the measured concentration to confirm the chamber operation. Theoretical concentration must agree with the measured concentration within 30 percent.

A.11 Analysis Procedure

Analyze the sorbent tubes following the procedures described in Section 11.0 of Method 325B.

A.12 Recordkeeping Procedures for Sorbent Tube Evaluation

Keep records for the sorbent tube evaluation to include at a minimum the following information:

A.12.1 Sorbent tube description and specifications.

A.12.2 Sorbent material description and specifications.

A.12.3 Volatile analytes used in the sampler test.

A.12.4 Chamber conditions including flow rate, temperature, and relative humidity.

A.12.5 Relative standard deviation of the sampler results at the conditions tested.

A.12.6 95 percent confidence limit on the sampler overall accuracy.

A.12.7 The relative accuracy of the sorbent tube results compared to the direct chamber measurement by direct gas chromatography or SUMMA canister analysis.

A.13 Method Performance

A.13.1 Sorbent tube performance is acceptable if the relative accuracy of the passive sorbent sampler agrees with the active measurement method by ±10 percent at the 95 percent confidence limit and the uptake ratio is equal to greater than 0.5 mL/min (1 ng/ppm-min).

Note: For example, there is a maximum deviation comparing Perkin-Elmer passive type sorbent tubes packed with Carbopack™ X of 1.3 to 10 percent compared to active sampling using the following uptake rates.

	1,3-butadiene uptake rate mL/min	Estimated detection limit (2 week)	Benzene uptake rates mL/min	Estimated detection limit (2 week)
Carbopack™ X (2 week)	0.61 ± 0.11 [a]	0.1 ppbv	0.67 [a]	0.05 ppbv

[a] McClenny, W.A., K.D. Oliver, H.H. Jacumin, Jr., E.H. Daughtrey, Jr., D.A. Whitaker. 2005. 24 h diffusive sampling of toxic VOCs in air onto Carbopack™ X solid adsorbent followed by thermal desorption/GC/MS analysis—laboratory studies. J. Environ. Monit. 7:248–256.

A13.2 Data Analysis and Calculations for Method Evaluation

A.13.2.1 Calculate the theoretical concentration of VOC standards using Equation A.1.

$$C_f = \left[\frac{FR_i}{FR_t + FR_a}\right] \times C_s \qquad \text{Eq. A.1}$$

Where:

C_f = The final concentration of standard in the exposure chamber (ppbv).

FR_i = The flow rate of the target compound I (mL/min).

FR_t = The flow rate of all target compounds from separate if multiple cylinders are used (mL/min).

FR_a = The flow rate of dilution air plus moisture (mL/min).

C_s = The concentration of target compound in the standard cylinder (parts per million by volume).

A.13.2.3 Determine the uptake rate of the target gas being evaluated using Equation A.2.

$$U = \frac{M_x}{C_e \times T_t} \qquad \text{Eq. A.2}$$

Where:

M_x = The mass of analyte measured on the sampling tube (ηg).

C_e = The theoretical exposure chamber concentration (ηg/mL).

T_t = The exposure time (minutes).

A.13.2.4 Estimate the variance (relative standard deviation (RSD)) of the inter-sampler results at each condition tested using Equation A.3. RSD for the sampler is estimated by pooling the variance estimates from each test run.

$$S^2 = \sum_{i}^{n} \frac{\left(X_i - \overline{X}\right)^2}{n-1} \qquad \text{Eq. A.3}$$

Where:

X_i = The measured mass of analyte found on sorbent tube *i*.

$\overline{X}_i$ = The mean value of all X_i.

n = The number of measurements of the analyte.

A.13.2.4 Determine the percent relative standard deviation of the inter-sampler results using Equation A.4.

$$\%RSD_x = 100 \times \frac{\sqrt{S^2}}{\overline{X}} \qquad \text{Eq. A.4}$$

A.13.2.5 Determine the 95 percent confidence interval for the sampler results using Equation A.5. The confidence interval is determined based on the number of test runs performed to evaluate the sorbent tube and sorbent combination. For the minimum test requirement of eight samplers tested at two concentrations, the number of tests is 16 and the degrees of freedom are 15.

$$\Delta_{95\%} = \frac{\%RSD \times t_{0.95} \times f}{\sqrt{n}} \qquad \text{Eq. A.5}$$

Where:

$\Delta_{95\%}$ = 95 percent confidence interval.
%RSD = percent relative standard deviation.
$t_{0.95}$ = The Students t statistic for f degrees of freedom at 95 percent confidence.
f = The number of degrees of freedom.
n = Number of samples.

A.13.2.6 Determine the relative accuracy of the sorbent tube combination compared to the active sampling results using Equation A.6.

$$RA = \overline{X_i} - \overline{X_A} \pm \Delta_{95\%} \qquad \text{Eq. A.6}$$

Where:

RA = Relative accuracy.
$\overline{X}_i$ = The mean value of all X_i.
$\overline{X}_i$ = The average concentration of analyte measured by the active measurement method.
$\Delta_{95\%}$ = 95 percent confidence interval.

A.14 Pollution Prevention

This method involves the use of ambient concentrations of gaseous compounds that post little or no pollution to the environment.

A.15 Waste Management

Expired calibration solutions should be disposed of as hazardous materials.

A.16 References

1. ISO TC 146/SC 02 N 361 Workplace atmospheres—Protocol for evaluating the performance of diffusive samplers.

[FR Doc. 2015–26486 Filed 11–30–15; 8:45 am]

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Part IV

Environmental Protection Agency

40 CFR Parts 60 and 63

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Technical Correction; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234 and EPA–HQ–OAR–2011–0044; FRL–9942–28–OAR]

RIN 2060–AS41

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Technical Correction

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; technical corrections.

SUMMARY: This action finalizes the technical corrections that the Environmental Protection Agency (EPA) proposed on February 17, 2015, to correct and clarify certain text of the EPA's regulations regarding ''National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units''. We are also taking final action to remove the rule provision establishing an affirmative defense for malfunction.

DATES: The effective date of this rule is April 6, 2016.

ADDRESSES: *Docket.* The EPA has established two dockets for this action: Docket ID No. EPA–HQ–OAR–2011–0044 (new source performance standards (NSPS) action) and Docket ID No. EPA–HQ–OAR–2009–0234 (Mercury and Air Toxics Standards (MATS) action). All documents in the dockets are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available (*e.g.,* confidential business information or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Avenue NW., Washington, DC 20004. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about the MATS action: Mr. Jim Eddinger, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5426; fax number (919) 541–5450; email address: *eddinger.jim@epa.gov.* For questions about the NSPS action: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–4003; fax number (919) 541–5450; email address: *fellner.christian@epa.gov.*

SUPPLEMENTARY INFORMATION:

A. How can I get copies of this document and other related information?

This **Federal Register** document and the document titled ''Summary of Public Comments and Responses: MATS and Utility NSPS Technical Corrections'' (TC RTC) are available in the dockets the EPA established under Docket ID No. EPA–HQ–OAR–2009–0234 and Docket ID No. EPA–HQ–OAR–2011–0044. The TC RTC is available in both the MATS and Utility NSPS dockets by conducting a search of the title ''Summary of Public Comments and Responses: MATS and Utility NSPS Technical Corrections.'' In addition to being available in the docket, electronic copies of these documents are available on the *www.regulations.gov* Web site. This **Federal Register** document and the TC RTC can also be found on the EPA's Technology Transfer Network (TTN) Web site at *http://www.epa.gov/ttn/atw/utility/utilitypg.html.*

B. Judicial Review

Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by June 6, 2016. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Note, 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 these requirements.

I. Background

The final Clean Air Act (CAA) rules published in the **Federal Register** on February 16, 2012 (77 FR 9303), establish national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units (EGUs), referred to as ''MATS,'' and NSPS for fossil-fuel-fired electric utility, industrial-commercial-institutional, and small industrial-commercial-institutional steam generating units, referred to as the ''Utility NSPS''.

In the February 17, 2015, **Federal Register** (80 FR 8442), the EPA proposed to correct certain regulatory text. The proposed corrections were categorized generally as follows: (a) Resolution of conflicts between preamble and regulatory text, (b) corrections that were inadvertently not made that the EPA stated it would make in response to comments, and (c) clarification of language in regulatory text. In the proposed rule, the EPA identified each proposed technical correction to the regulatory text as found in the Code of Federal Regulations (*i.e.,* 40 CFR). Table 1 of this preamble lists the proposed revisions to the regulatory text that the EPA is finalizing. In Table 2 below, the EPA lists additional changes that the Agency determined were necessary to conform to changes the Agency included in the proposed rule.

TABLE 1—SUMMARY OF PROPOSED TECHNICAL CORRECTIONS AND CLARIFICATIONS BEING FINALIZED

Section of subpart Da (40 CFR part 60)	Description of correction (40 CFR part 60)
40 CFR 60.48Da(f)	Revise procedures for calculating compliance with the NSPS daily average particulate matter (PM) emission limit using PM continuous emission monitoring system (CEMS).

Section of subpart UUUUU (40 CFR part 63)	Description of correction (40 CFR part 63)
40 CFR 63.9983(a)	Revise to clarify that MATS does not apply to either major or area source combustion turbines, except for integrated gasification combined cycle (IGCC) units.
40 CFR 63.9983(b) and (c)	Revise consistent with the definitional changes in 40 CFR 63.10042.
40 CFR 63.9983(e)	Add to clarify applicability to units meeting the definition of a natural gas-fired EGU in MATS, and, because they combust greater than 10 percent biomass, also meet the definition of a biomass-fired boiler in the Industrial Boiler NESHAP (subpart DDDDD).
40 CFR 63.9991(c)(1) and (2)	Revise to clarify the conditions that are required in order to use the alternate sulfur dioxide (SO_2) limit.
40 CFR 63.10000(c)(1)(i)(A) and 63.10005(h)	Revise to clarify the provisions of units designated as being low emitting EGUs (LEE) when an acid gas scrubber and a bypass stack are present.
40 CFR 63.10000(c)(1)(i)(C)	Add to allow EGUs the ability to seek LEE status if their bypass stacks that are able to measure emissions and to allow EGUs with LEE status the ability to bypass emissions control devices during emergency periods.
40 CFR 63.10000(c)(2)(iii)	Revise to state that EGU choosing to use quarterly testing and parametric monitoring for hydrogen fluoride (HF) or hydrogen chloride (HCl) compliance must include the continuous monitoring systems (CMS) in their site-specific monitoring plans.
40 CFR 63.10000(m)	Add to clarify that EGUs choosing to meet the work practice standards contained in paragraph (2) of the definition of startup may verify, instead of certify, monitoring systems used to meet the work practice standards.
40 CFR 63.10001	Revise to remove the affirmative defense provisions.
40 CFR 63.10005(a)	Revise to clarify that different compliance demonstrations may require different and additional types of data collection and to clarify the date by which compliance must be demonstrated for existing EGUs.
40 CFR 63.10005(a)(2)	Revise to clarify the date by which compliance must be demonstrated for EGUs using CMS or sorbent trap monitoring systems.
40 CFR 63.10005(a)(2)(i)	Revise to clarify applicability of the provision to both the 30- and 90-boiler operating day performance testing requirements.
40 CFR 63.10005(b)(6)	Add to clarify the date EGUs must begin conducting required stack tests when stack test data collected prior to the applicable compliance date are submitted to satisfy initial performance test.
40 CFR 63.10005(d)(3) and (d)(4)(i)	Revise to more clearly state when compliance must be demonstrated.
40 CFR 63.10005(f)	Revise to clarify when sources must complete the initial tune-up after the compliance date, and the timing for subsequent tune-ups when the initial tune-up is conducted prior to the compliance date.
40 CFR 63.10005(h)(3)	Revise to clarify that the alternate 30- and 90-day averaging provisions are both applicable to mercury (Hg) emission limits.
40 CFR 63.10005(i)(4)	Revise to delete paragraphs (iii) and (iv). The identified test methods are not for determining fuel moisture content, as required in the provision.
40 CFR 63.10006(f)	Revise to specify EGU operational status with respect to performance testing; the requirements if the performance testing schedule is missed; and intervals between performance tests.
40 CFR 63.10009(a)(2) and (a)(2)(i)	Revise to clarify that the 90-boiler operating day averaging period is an option for Hg emissions from non-low rank virgin coal-fired EGUs.
40 CFR 63.10009(b)(1)	Revise to clarify group eligibility equations 1a and 1b.
40 CFR 63.10009(b)(2), (b)(3), (f)(2), (g)(1), (g)(2), and (j)(1)(ii).	Revise to correct the term ''gross electric output'' to ''gross output'' which is the term defined in 40 CFR 63.10042.
40 CFR 63.10009(f)	Revise to clarify the conditions for determining the ability of the emissions averaging group to meet the emissions limit and to clarify use of the alternate Hg emission limit.
40 CFR 63.10010(a)(4)	Revise to add requirement to route exhaust gases that bypass emissions control devices through stacks that contain monitoring so that emissions can be measured and to clarify that hours that a bypass stack is in use are to be counted as hours of deviation from monitoring requirements.
40 CFR 63.10010(f)(3)	Revise to clarify that 30-boiler operating day rolling averages are based only on valid hourly SO_2 emission rates.
40 CFR 63.10010(h)(6)(i) and (ii), (i)(5)(i)(A) and (B), and (j)(4)(i)(A) and (B).	Revise to clarify that data collected during certain periods are not to be included in compliance assessments but such periods are to be included in annual deviation reports.
40 CFR 63.10010(j)(l)(i)	Revise to replace the incorrect reference to § 63.7(e) with the correct reference to § 63.8(d)(2).
40 CFR 63.10010(l) and (l)(4)	Revise to clarify that EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup may verify, instead of certify, monitoring systems used.
40 CFR 63.10011(b)	Revise to remove the incorrect reference to Table 4 and to replace the incorrect reference to Table 7 with the correct reference to Table 6.

TABLE 1—SUMMARY OF PROPOSED TECHNICAL CORRECTIONS AND CLARIFICATIONS BEING FINALIZED—Continued

Section of subpart UUUUU (40 CFR part 63)	Description of correction (40 CFR part 63)
40 CFR 63.10011(c)(1) and (2)	Revise to clarify the date by which compliance must be demonstrated by EGUs that use CEMS or sorbent trap monitoring systems and to clarify in 40 CFR 63.10011(c)(1) that the alternate Hg emission limit may be used.
40 CFR 63.10011(e)	Revise to replace "according to" with "in accordance with."
40 CFR 63.10011(g)(4)(v)(A) and Table 3	Revise to clarify our intent by changing "to the maximum extent possible" to "to the maximum extent possible, taking into account boiler or control device integrity."
40 CFR 63.10020(e)	Revise to clarify that it applies only to EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup. In addition, the undefined term "electrical load" has been replaced with the defined term "gross output" and the incorrect terms "liquid to fuel ratio" and "the differential pressure of the liquid" have been replaced with the correct terms "liquid to flue gas ratio" and "the pressure drop across the scrubber."
40 CFR 63.10021(d)(3)	Revise to clarify the type of monitoring that is to be used to demonstrate compliance.
40 CFR 63.10021(e)	Revise to clarify the condition that allows delay of burner inspections for initial tune-ups.
40 CFR 63.10021(e)(9)	Revise to clarify the dates that tune-ups must be reported.
40 CFR 63.10023(b) and Table 6	Revise to clarify that all EGUs using PM continuous parametric monitoring systems (CPMS) for compliance purposes are to follow the same procedure for determining the operating limit.
40 CFR 63.10030(e)(1)	Revise to replace the phrase "identification of which subcategory the source is in" with "identification of the subcategory of the source."
40 CFR 63.10030(e)(7)(i)	Revise to delete and reserve since subsequent performance tests are not part of the Notification of Compliance Status.
40 CFR 63.10030(e)(7)(iii)	Add to establish the procedures by which an EGU owner or operator may switch between mass per heat input and mass per gross output emission limits.
40 CFR 63.10030(e)(8)(i)	Revise to clarify that it applies only to EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup. Revise to clarify that PM control device efficiencies and PM emission rates are those of periods other than startup and shutdown periods.
40 CFR 63.10030(e)(8)(ii)	Revise to remove the requirement for use of an independent professional engineer.
40 CFR 63.10030(f)	Revise to add notification requirements for EGUs that move in and out of MATS applicability.
40 CFR 63.10031(c)(4)	Revise to clarify the reporting requirements for EGU tune-ups.
40 CFR 63.10031(c)(5)	Revise to clarify that it applies only to EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup.
40 CFR 63.10031(c)(6)	Revise to add emergency bypass reporting for EGUs with LEE status.
40 CFR 63.10032(f)	Revise to clarify that the requirements of § 63.10032(f)(1) apply only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (1) of the definition of startup, while the requirements of § 63.10032(f)(2) apply only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup.
40 CFR 63.10042	The definitions of "Coal-fired electric utility steam generating unit," "Coal refuse," "Fossil fuel-fired," "Integrated gasification combined cycle electric utility steam generating unit or IGCC," "Limited-use liquid oil-fired subcategory," "Natural gas-fired electric utility steam generating unit," and "Oil-fired electric utility steam generating unit" are revised to clarify the period of time to be included in determining the source's applicability to the MATS. A definition of "neural network" is added because the term is used in 40 CFR 63.10005(f), 63.10006(i), and 63.10021(e) and Table 3 to subpart UUUUU of Part 63 but is not defined.
Table 1 to subpart UUUUU of part 63	Revise to correct the term "gross electric output" to "gross output" which is the term defined in 40 CFR 63.10042.
Table 2 to subpart UUUUU of part 63	Revise to correct the term "gross electric output" to "gross output" which is the term defined in 40 CFR 63.10042. Provision 1(c) (the Hg limit for EGUs in the subcategory "unit designed for coal ≥8,300 Btu/lb") is also revised to clarify the applicability of the alternate 90-boiler operating day compliance option.
Table 3 to subpart UUUUU of part 63	Revise as described earlier to clarify the term "maximum extent possible.".
Table 4 to subpart UUUUU of part 63	Revise to clarify that existing as well as new EGUs using PM CPMS share the same procedures for developing operating limits.
Table 5 to subpart UUUUU of part 63	Revise to clarify that when using Method 29, the metals matrix spike and recovery levels are to be reported.
Table 6 to subpart UUUUU of part 63	Revise to clarify that existing, as well as new, EGUs using PM CPMS share the same procedures for developing operating limits.
Table 8 to subpart UUUUU of part 63	Revise to clarify that compliance reports are to include information required by 40 CFR 63.10031(c)(5) and (6).
Table 9 to subpart UUUUU of part 63	Revise to correct an inadvertent omission of 30-day notification requirements of 40 CFR 63.9.
Paragraphs 4.1.1.3 and 5.1.2.3 and Tables A–1 and A–2 to appendix A.	Revise to adjust Hg CEMS language regarding converters.
Paragraph 7.1.2.5 to appendix A	Add to require that owners or operators flag EGUs that are part of emission averaging groups.
Paragraph 3.2.1.2.1 of appendix A	Revise to specifically indicate that Hg gas generators and cylinders are allowed.
Paragraphs 4.1.1.1, Table A–1, Table A–2, 5.1.2.1, and 4.1.1.3 of appendix A.	Revise to exclude use of oxidized Hg gas standards for daily calibration of Hg CEMS.
Paragraph 5.1.2.3 of appendix A	Revise to make the weekly single level system integrity check mandatory.

TABLE 1—SUMMARY OF PROPOSED TECHNICAL CORRECTIONS AND CLARIFICATIONS BEING FINALIZED—Continued

Section of subpart UUUUU (40 CFR part 63)	Description of correction (40 CFR part 63)
Paragraphs 4.1.1.5.2, Table A–1, Table A–2, and 4.1.1.5 of appendix A.	Revise to provide an alternative relative accuracy test audit (RATA) procedure for EGUs with low emissions.
Paragraph 5.2.1 of appendix A	Revise to correct the number of days for sorbent trap use from 14 to 15.
Paragraph 6.2.2.3 of appendix A	Revise to clarify that the 90-day alternative Hg standard may be used and that electrical output is gross output.
Paragraph 7.1.2.6 of appendix A	Add to clarify that EGU owners or operators are to keep records of their EGUs that constitute emissions averaging groups.
Paragraphs 2.1, 2.3, 2.3.1, 2.3.2, 3.1, 3.2, 3.3, 5, 5.1, 5.2, and 5.3 of appendix B.	Revise to clarify that use of Performance Specification (PS) 18, when promulgated, will be allowed.
Paragraph 5.4 of appendix B	Add as part of the renumbering due to the addition of PS 18.
Paragraph 8 of appendix B	Revise to accommodate use of PS 18.
Paragraphs 10.1.8, 10.1.8.1, 10.1.8.1.1, and 10.1.8.1.2 of appendix B.	Revise as part of the renumbering due to the addition of PS 18.
Paragraph 10.1.8.1.3 of appendix B	Revise to clarify that records of relative accuracy audits (RAAs) are also required.
Paragraphs 10.1.8.2, 10.1.8.1.2.1, and 10.1.8.1.2.2 of appendix B.	Revise to clarify the quarterly gas audit recordkeeping requirements for PS 15 and the quarterly data accuracy assessments for PS 18 (which are reserved).
Paragraph 11.4 of appendix B	Revise to replace the incorrect abbreviation "*i.e.*" with "*e.g.*".
Paragraph 11.4.2 of appendix B	Revise to specify the requirements of the daily beam intensity checks for EGUs using PS 18.
Paragraph 11.4.3 of Appendix B	Revise to reflect the reporting requirements for PS 15.
Paragraph 11.4.4 of appendix B	Revise to reserve the reporting requirements for quarterly parameter verification checks for PS 18.
Paragraphs 11.4.4.1, 11.4.5, 11.4.5.1, 11.4.6, 11.4.6.1 of appendix B.	Add to reserve the reporting requirements for quarterly gas audit information and for quarterly dynamic spiking for PS 18.
Paragraph 11.4.7 of appendix B	Add to include reporting requirements for RAAs.
Paragraphs 11.4.7.1 through 11.4.7.13 of appendix B.	Add as part of the renumbering due to the addition of PS 18.
Paragraph 11.5.3.4 of appendix B	Revise to include reporting requirements for beam intensity checks for PS 18.

Most of the corrections and clarifications remain the same as presented in the proposed correction document and those changes are being finalized without further discussion. However, the EPA has made some changes in this final rule after consideration of the public comments received on the proposed correction document. The changes are to clarify applicability and implementation issues associated with proposed changes, and the significant changes are discussed below in this preamble. A summary of the comments received and our responses thereto is contained in the document ''Summary of Public Comments and Responses: MATS and Utility NSPS Technical Corrections'' located in the dockets for these rulemakings.

II. Significant Changes Since Proposal

This section of the preamble summarizes the significant changes made to the proposed corrections and clarifications.

1. Section 63.9984(f) is revised to add ''or the EGU's otherwise applicable compliance date established by the EPA or the state.'' A commenter stated that the EPA's proposed revision, which was adding ''the date that compliance must be demonstrated, as given'' in § 63.9984, to the initial compliance requirements in § 63.10005(a) for existing EGUs, does not effectively clarify the date that compliance must be demonstrated due to its reference to § 63.9984 and paragraph (f) of § 63.9984 because § 63.9984(b) specifies a compliance date of April 16, 2015 for existing EGUs. Also, § 63.9984(f), which states the dates by which compliance must be demonstrated, refers to § 63.9984(b). Therefore, we revised § 63.9984(f) because specifying a date for existing EGUs to demonstrate compliance is confusing for existing sources that have been granted a compliance extension.

2. Section 63.10000(n) is added to address comments that noted the proposed technical corrections did not address the permanent conversion to natural gas or biomass consistent with the proposals outlined in the February 17, 2015 preamble. In the preamble (see 80 FR 8447), we stated ''The EPA is also proposing that sources that permanently convert to natural gas or biomass after the compliance date are no longer subject to MATS, notwithstanding the coal or oil usage the previous 3 calendar years.'' However, we inadvertently did not include the necessary language to address permanent conversions in the proposed regulatory text. For that reason, we are revising paragraph (n) to incorporate the proposed change as outlined in the preamble to the proposed rule.

3. The proposal to revise § 63.10005(b)(1) to change the time period allowed for existing EGUs to use stack test data collected prior to the applicable compliance date has been withdrawn. Several commenters did not support the proposed revision to change the window in which initial compliance can be demonstrated, and said that EGUs should be allowed to demonstrate initial compliance using stack tests conducted on or after April 16, 2014. Commenters said the EPA's proposed change is unfair, renders investments in stack testing useless, and requires companies to perform new, unnecessary initial compliance testing. For these reasons, and because the Agency believes earlier stack tests may be representative under certain circumstances, the EPA is not making the proposed change.

4. Section 63.10006(f) is revised to: (1) Correct the minimum time between annual performance tests (from 370 to 320 calendar days); (2) clarify the minimum time between annual sorbent trap mercury testing for 30-boiler operating day low emitting EGU (LEE) retests (also 320 calendar days); and (3) provide the minimum time between annual sorbent trap mercury testing for 90-boiler operating day LEE retests (230 calendar days). Commenters correctly stated that the 370-day interval for annual tests was a typographical error, as they would expect the interval to be 365 days or less. Commenters expressed concerns that, while the proposed revised § 63.10006(f) specified the time

periods between annual performance tests, it did not specify the time periods between annual sorbent trap mercury testing for either the 30-boiler operating day averaging periods or the 90-boiler operating day averaging periods. The three revisions, listed above, being made to § 63.10006(f) address the commenters' concerns. In addition, § 63.10010(i)(2)(i) and (ii) is revised to clarify the time periods between quarterly, annual, and three year testing for particulate matter continuous emissions monitoring system (PM CEMS) audits.

5. Section 63.10009(b)(1) is revised to clarify group eligibility equations 1a and 1b. The purpose of the group eligibility equations is to provide EGU owners or operators a quick method for demonstrating initial compliance with the emission limits for all units participating in the emission averaging group using the maximum rated heat input or gross output of each unit and the results of the initial compliance demonstrations. Commenters stated that the EPA proposed to drop the double summation in the denominator, which is a correct step. However, the commenters indicated they do not understand what the Agency was thinking with respect to adding the ''q_j'' term in both the numerator and denominator and that the EPA defined ''q_j'' to be the hours in the averaging period (720 for 30-day averages and 2,160 for 90-day averages) because the term's presence in both the numerator and denominator cancels out and has no effect. Commenters also stated that they do not agree that the newly proposed group averaging eligibility Equation 1a is more useful than the original equation. Commenters said both the original equation and the newly proposed equation are flawed and, thus, produce incorrect results. Commenters said corrections need to be made to either equation that the EPA wants to use. Commenters said the stack testing components of the equation for each unit that is tested need to be weighted the same as units that use continuous monitoring in order for any equation to produce correct calculations. Commenters said the original equation works for the continuous monitoring components, but is flawed because it does not properly weight the stack testing components, and the newly proposed equation is flawed on both fronts. Based on the commenters' concerns, the equations have been revised so that individual EGU characteristics, whether from continuous emission monitoring systems (CEMS) or stack testing results, are easier to input. We agree that the added ''q_j'' term and ''r_k'' term have no effect, and they have been deleted. We are also deleting the ''n'' term since Equations 1a and 1b are to demonstrate initial compliance based on using the initial compliance results and not continuous compliance that is based on an averaging period. We have revised some of the terms' descriptions to clarify that the emission rates used are those determined during the initial compliance demonstration.

6. Section 63.10009(e), (g), and (j)(2) are revised to require compliance with the weighted average emissions rate at all times following the date that emissions averaging begins. A commenter argued that the EPA must also revise these sections to remove the specifically identified dates (*e.g.,* April 16, 2015 and February 16, 2015). We agree that the dates within § 63.10009(e), (g), and (j)(2) should be removed, and the dates have been replaced with ''the date that you begin emission averaging.''

7. Section 63.10010(h)(6)(i), (i)(5)(i)(A), and (j)(4)(i)(A) and (B) are revised to clarify when monitoring system quality assurance or quality control activities are to be reported. Commenters said § 63.10010(h)(6)(i), (i)(5)(i)(A), and (j)(4)(i)(A) and (B) specify what data from particulate matter (PM) continuous parameter monitoring system (CPMS), PM CEMS, and hazardous air pollutants (HAP) metal CEMS must be excluded from compliance determinations and that the EPA proposed to separate the language regarding deviation reporting that currently appears at the end of these provisions into a separate sentence to ''ease readability.'' The commenter disagreed that the proposed revision improves readability and said that, to the contrary, by separating out the sentence, the EPA implies that the periods when data are not collected because of monitoring system malfunctions, repairs, required quality assurance or quality control, as well as periods when a monitoring system is out of control, are deviations from monitoring requirements, which they are not. The commenter is incorrectly interpreting the proposed change. Periods when data are not collected because of monitoring system malfunctions are deviations. The required quality assurance or quality control activities that are deviations from monitoring requirements are, as stated in § 63.10010(h)(6)(i), (i)(5)(i)(A), and (j)(4)(i)(A) and (B), those conducted during monitoring systems malfunctions.

8. Section 63.10011(g)(4)(v)(A) is revised to change the proposed language ''to the maximum extent practicable'' back to the language ''to the maximum extent possible'' as in the final rule. Commenters said the requirement to use clean fuels ''to the maximum extent practicable'' does not even address the level of toxic emissions during startup, let alone reduce them to the maximum extent achievable as is required under CAA section 112(d)(2). Commenters said, perhaps most importantly, that the EPA's proposed change impermissibly assumes that existing older boilers and control devices are not capable of being upgraded—despite Congress' mandate in CAA section 112(d)(2)–(3) that emissions standards and work practices reflect what is achievable and actually being achieved by the best-performing sources. Commenters said further, under CAA section 112(d), it is the Administrator's duty to establish standards to achieve the required emissions reductions—not the duty of owners and operators. Commenters said the EPA's purported work practices impermissibly allow operators themselves to determine the standards and their own emission reductions achieved (or not) by the requirements. Commenters said the EPA's proposed change leaves it up to each operator to determine the amount of clean fuel use that represents the ''maximum extent practicable,'' and leaves it up to each operator to determine what qualifies as a ''consideration such as boiler or control device integrity.'' Commenters said that even though the requirement for clean fuels states that EGUs must have sufficient clean fuel capacity to engage and operate PM control devices within 1 hour of adding the primary fuel (and even though a separate work practice requires PM controls to be engaged and operated within 1 hour), these requirements do not establish whether and to what point EGUs must actually use clean fuels in startups. These comments primarily concern issues that the EPA did not reopen in the proposed document. Because those issues were not reopened, the EPA did not respond to these comments. We did propose to change § 63.10011(g)(4)(v)(A) as the commenter states. We continue to believe that the use of clean fuels during startup must be maximized to reduce HAP emissions and have reconsidered the proposed change of ''possible'' to ''practicable.'' We believe ''possible'' is a more enforceable standard. The final change to § 63.10011(g)(4)(v)(A) is: ''to the maximum extent possible, taking into account considerations such as boiler or control device integrity,

throughout the startup period.'' This language is also included in section 4 of Table 3, to clarify that this provision applies during periods of shutdown.

The EPA is not finalizing the proposed change because we have determined that requiring clean fuel use to the maximum extent ''possible'' is more enforceable than the proposed change to ''practicable'', and the Agency believes it is critical that the work practice be enforceable to ensure that sources use as much clean fuel with its inherently low HAP content as possible when a source's controls are not yet fully engaged. At the same time, we believe operators must be able to consider the integrity of the EGU system when determining the clean fuel use that is ''possible'' for a given unit. We believe the final rule addresses both considerations.

9. Section 63.10030(e)(8)(iii) is added to allow EGU owners or operators the ability to switch between paragraphs 1 and 2 of the startup definition. Commenters requested that switching between paragraphs of the definition of startup not be prohibited. We have no objection to such switching provided certain criteria are met. Just as we had not considered that EGU owners or operators would want to switch between mass per year heat input emission limits and mass per gross output emission limits, but proposed to allow such changes provided certain criteria are met, we did not consider that an owner or operator would want to switch between the startup definitions for the EGU. Given the commenter's specific request and the EPA's conditional approval based on the already existing model given in § 63.10030(e)(7)(iii)(A), § 63.10030(e)(8)(iii) is added to the rule. This new section allows EGU owners or operators the ability to switch between paragraphs 1 and 2 of the startup definition provided, among other things, that the EGUs involved in the switch are identified, that a request is submitted 30 days prior to the anticipated switch, that the request contains certification that all previous plans, such as monitoring and emissions averaging, are revised, that records are maintained, and that the new definition is not used until the next reporting period after receipt of written acknowledgement from the Administrator or the delegated authority of the switch.

10. Section 63.10031(c)(4) is revised to clarify that the ''date'' of the tune-up is the date the tune-up provisions specified in § 63.10021(e)(6) and (7) are completed. Commenters noted that there will not necessarily be a single date associated with completion of an EGU's tune-ups conducted under § 63.10021(e) and suggested that, related to the possibility of a delayed burner inspection, the Agency make it clear that compliance with all requirements besides the burner inspection must occur by the compliance demonstration date, but that the burner inspection may be delayed, and to revise the provision to recognize that as a result, performance of subsequent inspections and tune-ups may be on a separate 36-month track and some EGUs may have ''dates'' rather than a ''date'' for completion of requirements. Regardless of when the burner inspection is conducted, the tune-up is considered to have been conducted on the date the combustion optimization is completed. The purpose of the tune-up is the optimization of the combustion to minimize organic HAP, carbon monoxide, and nitrogen oxides (NO_X) and to improve or return the unit to its design combustion efficiency (*i.e.,* § 63.10021(e)(6) and (7)). We realize that EGUs may need to be taken off-line to conduct an inspection of burners. So, we allow that inspection to be delayed, or as § 63.10021(e) is revised, to be performed prior to the tune-up. Therefore, subsequent tune-ups must be performed within 36 months from when the previous tune-up (*i.e.,* the requirements of § 63.10021(e)(6) and (7)) was completed, and the source must conduct the next burner inspection on a similar schedule.

11. Section 63.10031(c)(7) is added to include the reporting requirements that have been removed from § 63.10030(e)(7)(i). A commenter said that there is no reason to submit Notification of Compliance Status (NOCS) for ongoing 3-year tests that are performed to demonstrate that LEE status is maintained, so the proposed language in § 63.10030(e)(7)(i) should be revised. We agree that not only the ongoing 3-year LEE retests, but also the annual and quarterly LEE retests and annual retests that are performed to establish operating limits, should not be submitted as NOCS. According to the introductory text of § 63.10030(e), the NOCS is required only for reporting initial compliance. Therefore, § 63.10030(e)(7)(i) has been removed and reserved, and the reporting requirements in § 63.10030(e)(7)(i) have been moved to a new place, *i.e.,* § 63.10031(c)(7), and are part of the compliance report requirements. Likewise, the compliance certification and deviation information requirements in § 63.10030(e)(5) and (e)(6) apply for compliance reports and are replicated in new § 63.10031(c)(8) and (9), and each of these paragraphs is included in the introductory text in § 63.10030(c) and in Table 8.

12. The definitions of ''Coal-fired electric utility steam generating unit,'' ''Fossil fuel-fired,'' ''Limited-use liquid oil-fired subcategory,'' and ''Oil-fired electric utility steam generating unit'' in § 63.10042 are further revised to clarify the period of time to be included in determining the source's applicability to the MATS.

One commenter indicated that the proposed rule does not address permanent conversion to natural gas or biomass, nor does it make clear that, after the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the 3 previous calendars years on an annual rolling basis. The commenter said that the EPA's clarifying proposals are not clearly outlined in the proposed revised definitions. The commenter urged the EPA to revise the definition in a manner consistent with the proposals outlined in the preamble. Several commenters indicated the proposed changes do not prevent an EGU from continuing to be subject to MATS for several years after a fuel switch.

We agree that the proposed clarification to the definitions does not make it clear that, after the first 3 years of compliance, an EGU is required to evaluate applicability based on coal or oil usage from the 3 previous calendar years on an annual rolling basis. Thus, we have revised the definitions for ''Coal-fired electric utility steam generating unit,'' ''Oil-fired electric utility steam generating unit,'' and ''Fossil fuel-fired'' to clarify that applicability after the first 3 years of compliance will be based on coal or oil usage from the 3 previous calendar years on an annual rolling basis.

Concerning the permanent fuels switch, the EPA explained above that it has addressed permanent conversions in § 63.10000(n) of the final rule, as discussed in paragraph 2 above.

13. Appendix A is finalized with all proposed revisions with the exception of adding an alternative specification for the relative accuracy test audit (RATA) where commenters provided data to support a different approach using an absolute value criterion. However, due to the current lack of available NIST-traceable elemental Hg gas cylinders, owners or operators of EGUs that have purchased/installed Hg CEMS that lack integrated elemental Hg gas generators may continue to use NIST-traceable oxidized gases for calibration error tests and daily checks until such time that NIST-traceable compressed elemental Hg gas standards are available and traceable with a combined uncertainty

(K=2) of 5 percent. Once those standards are available, we will issue a notice of availability in the **Federal Register**. Should NIST-traceable oxidized mercury reference gases with a combined uncertainty of 5% ultimately be available, we will consider allowing their use for calibration error tests and checks.

14. Appendix B is finalized with all proposed revisions except those related to sections 10 and 11 regarding recordkeeping and reporting for hydrogen chloride (HCl) CEMS subject to PS 18. Sections 10 and 11 will be addressed in the upcoming MATS Completion of Electronic Reporting Requirements rule. One change has been made that was not proposed. A minor technical correction has been made to section 9.4, requiring the HCl emission rates to be reported to 2 significant figures in scientific notation, which is consistent with the way that the emission standards are presented in Tables 1 and 2.

III. Other Corrections and Clarifications

In finalizing the rule, the EPA is addressing several other technical corrections and clarifications in the regulatory language based on public comments that were received on the February 2015 proposal that the Agency determined were necessary to conform to changes included in the proposed rule, as outlined in Table 2 of this preamble.

TABLE 2—SUMMARY OF TECHNICAL CORRECTIONS AND CLARIFICATIONS SINCE FEBRUARY 17, 2015, PROPOSAL

Section of subpart UUUUU (40 CFR part 63)	Description of correction (40 CFR part 63)
40 CFR 63.10000(a)	Revise this paragraph by adding "items 3 and 4" to clarify which items in Table 3 must be met.
40 CFR 63.10000(f)	Revise this paragraph to add "Except as provided under paragraph (n) of this section" due to the addition of paragraph (n) clarifying the applicability of a permanent conversion to natural gas or biomass.
40 CFR 63.10000(g)	Revise this paragraph to add "Except as provided under paragraph (n) of this section" due to the addition of paragraph (n) clarifying the applicability of a permanent conversion to natural gas or biomass.
40 CFR 63.10000(i)(1)	Revise this paragraph to clarify that an EGU, no longer subject to MATS, must be in compliance with applicable CAA section 112 or 129 standards consistent with paragraphs (g) and (n).
40 CFR 63.10005(a)	Revise this paragraph to replace the terms "electrical" and "electrical load" with the terms "gross" and "gross output," respectively, to be consistent with the proposed changes to other sections.
40 CFR 63.10005(a)(2)(ii)	Revise this paragraph to replace the terms "electrical" and "electrical load" with the terms "gross" and "gross output," respectively, to be consistent with the proposed changes to other sections.
40 CFR 63.10005(b)(4)	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.
40 CFR 63.10005(f)	Revise to be consistent with EPA's intent, as explained in the preamble to the proposed rule, to only clarify the timing of initial and subsequent tune-ups. Revise since specifying the date is problematic for sources that have been granted a compliance extension.
40 CFR 63.10005(h)(3)(i)(D)	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.
40 CFR 63.10005(h)(3)(iii)	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.
40 CFR 63.10007(f)(2)	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.
40 CFR 63.10009(e) and (j)(2)	Revise since specifying the date is problematic for sources that have been granted a compliance extension.
40 CFR 63.10010(f)(4)	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.
40 CFR 63.10021(h)(1)	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.
Table 5	Revise this table to replace the term "electrical" with the term "gross" to be consistent with the proposed changes to other sections.
Paragraph 7.1.8.5 of appendix A	Revise this paragraph to replace the term "electrical load" with the term "gross output" to be consistent with the proposed changes to other sections.

IV. Affirmative Defense for Violation of Emission Standards During Malfunction

The EPA received numerous comments on the affirmative defense to civil penalties for violations caused by malfunctions that the EPA proposed to remove in the current rule. Several commenters supported the removal of the affirmative defense for malfunctions. Other commenters opposed the removal of the affirmative defense provision.

As stated in the February 17, 2015, proposal, the United States Court of Appeals for the District of Columbia Circuit vacated an affirmative defense in one of the EPA's CAA section 112(d) regulations. *NRDC* v. *EPA,* No. 10–1371 (D.C. Cir. April 18, 2014) 2014 U.S. App. LEXIS 7281 (vacating affirmative defense provisions in CAA section 112(d) rule establishing emission standards for Portland cement kilns). The court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts in such cases lies exclusively with the courts, not the EPA. Specifically, the court found: "As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are 'appropriate.' " See *NRDC,* 2014 U.S. App. LEXIS 7281 at *21 ("[U]nder this statute, deciding whether penalties are 'appropriate' in a given private civil suit is a job for the courts, not EPA.''). The EPA is finalizing the proposed removal of the regulatory affirmative defense provision from MATS. In the event that a source fails to comply with an applicable CAA section 112(d) standard as a result of a malfunction event, the EPA's ability to exercise its case-by-case-enforcement discretion to determine an appropriate response provides sufficient flexibility in such circumstances as was explained in the preamble to the proposed rule. Further, as the D.C. Circuit recognized, in an EPA or citizen enforcement action, the court has the discretion to consider any defense raised and determine whether penalties are appropriate. Cf. NRDC, 2014 U.S. App. LEXIS 7281 at *24 (arguments that violation were caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same is true for the presiding officer in EPA administrative enforcement actions. For all these reasons, this final rule removes the affirmative defense provisions.

V. Impacts of This Final Rule

This action finalizes certain provisions and makes technical and clarifying corrections, but does not promulgate substantive changes to the February 2012 final MATS (77 FR 9304). Therefore, there are no environmental, energy, or economic impacts associated with this final action. The impacts associated with MATS are discussed in detail in the February 16, 2012, final MATS rule.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.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 not a significant regulatory action and was, therefore, not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities contained in the existing regulations (40 CFR part 63, subpart UUUUU) and has assigned OMB control number 2060–0567. This action is believed to result in no changes to the ICR of the February 2012 final MATS rule, so that the information collection estimate of project cost and hour burden from the final MATS have not been revised.

C. 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. This action will not impose any requirements on small entities. This action finalizes changes to MATS to correct and clarify implementation issues raised by stakeholders.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This rule promulgates amendments to the February 2012 final MATS, but the amendments are clarifications to existing rule language to aid in implementation. Therefore, the action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

E. 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.

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

This action does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. This action clarifies certain components of the February 2012 final MATS. Thus, Executive Order 13175 does not apply to this action.

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

The EPA interprets Executive Order 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 Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

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

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

I. National Technology Transfer and Advancement Act (NTTAA)

This action does not involve technical standards from those contained in the February 16, 2012, final rule. Therefore, the EPA did not consider the use of any voluntary consensus standards. *See* 77 FR 9441–9443 for the NTTAA discussion in the February 16, 2012, final rule.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will **not** have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations because it does not affect the level of protection provided to human health or the environment.

The environmental justice finding in the February 2012 final MATS remains relevant in this action, which finalizes changes to the rule to correct and clarify implementation issues raised by stakeholders.

K. Congressional Review Act (CRA)

This action is subject to the 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

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: March 17, 2016.

Gina McCarthy,

Administrator.

For the reasons discussed in the preamble, the EPA amends 40 CFR parts 60 and 63 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.*

■ 2. Section 60.48Da is amended by revising paragraph (f) to read as follows:

§ 60.48Da Compliance provisions.

* * * * *

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with the applicable daily average PM emissions limit is determined by calculating the arithmetic average of all hourly emission rates each boiler operating day, except for data obtained during startup, shutdown, or malfunction periods. Daily averages are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control data daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance. For affected facilities for which construction or reconstruction commenced after May 3, 2011 that elect to demonstrate compliance using PM CEMS, compliance with the applicable PM emissions limit in § 60.42Da is determined on a 30-boiler operating day rolling average basis by calculating the arithmetic average of all hourly PM emission rates for the 30 successive boiler operating days, except for data obtained during periods of startup and shutdown.

* * * * *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 3. The authority citation for part 63 continues to read as follows:

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

■ 4. Section 63.9983 is amended by:

■ a. Revising the section heading and paragraphs (a), (b), and (c); and

■ b. Adding paragraph (e).

The revisions and addition read as follows:

§ 63.9983 Are any fossil fuel-fired electric generating units not subject to this subpart?

* * * * *

(a) Any unit designated as a major source stationary combustion turbine subject to subpart YYYY of this part and any unit designated as an area source stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and that meets the definition of a natural gas-fired EGU in § 63.10042.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but does not meet the definition of a coal- or oil-fired EGU because it did not fire sufficient coal or oil to satisfy the average annual heat input requirement set forth in the definitions for coal-fired and oil-fired EGUs in § 63.10042. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).

* * * * *

(e) Any electric utility steam generating unit that meets the definition of a natural gas-fired EGU under this subpart and that fires at least 10 percent biomass is an industrial boiler subject to standards established under subpart DDDDD of this part, if it otherwise meets the applicability provisions in that rule.

■ 5. Section 63.9991 is amended by revising paragraphs (c)(1) and (2) to read as follows:

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

* * * * *

(c) * * *

(1) Has a system using wet or dry flue gas desulfurization technology and an SO_2 continuous emissions monitoring system (CEMS) installed on the EGU; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology and the SO_2 CEMS installed on the EGU consistent with § 63.10000(b).

■ 6. Section 63.10000 is amended by revising paragraphs (a), (c)(1)(i), (c)(2)(iii), (f), (g), and (i)(1) and adding paragraphs (m) and (n) to read as follows:

§ 63.10000 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements, items 3 and 4, in Table 3 to this subpart during periods of startup or shutdown.

* * * * *

(c)(1) * * *

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct initial performance testing in accordance with § 63.10005(h), to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs (c)(1)(i)(A) and (B) of this section:

(A) Except as provided in paragraph (c)(1)(i)(C) of this section, you may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device.

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-derived fuel-fired EGU or IGCC EGU is new.

(C) You may pursue the LEE option provided that:

(*1*) Your EGU's control device bypass emissions are measured in the bypass stack or duct or your control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event; or

(*2*) Except for hours during which only clean fuel is combusted, you bypass your EGU control device only during emergency periods for no more than a total of 2 percent of your EGU's annual operating hours; you use clean fuels to the maximum extent possible during an emergency period; and you prepare and submit a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. You must include these emergency emissions along with performance test results in assessing whether your EGU maintains LEE status.

* * * * *

(2) * * *

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance through quarterly performance testing and parametric monitoring for HCl and HF. If you choose to use quarterly testing and parametric monitoring, then you must also develop a site-specific monitoring plan that identifies the CMS you will use to ensure that the operations of the EGU remains consistent with those during the performance test. As another alternative, you may measure or obtain, and keep records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

* * * * *

(f) Except as provided under paragraph (n) of this section, you are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (*e.g.,* 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless your unit is a solid waste incineration unit subject to standards under CAA section 129 (*e.g.,* 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

(g) Except as provided under paragraph (n) of this section, if your unit no longer meets the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that your unit last met the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with § 63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.

* * * * *

(i)(1) If you own or operate an EGU subject to this subpart and cease to operate in a manner that causes your unit to meet the definition of an EGU subject to this subpart, you must be in compliance with any newly applicable section 112 or 129 standards on the date you selected consistent with paragraphs (g) and (n) of this section.

* * * * *

(m) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU, on or before the date your EGU is subject to this subpart, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with § 63.10020(e).

(1) You may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system.

(2) You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.

(n) If you have permanently converted your EGU from coal or oil to natural gas or biomass after your compliance date (or, if applicable, after your approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents you from operating in a manner that would subject you to this subpart, you are no longer subject to this subpart, notwithstanding the coal or oil usage in the previous calendar years. The date on which you are no longer subject to this subpart is the date on which you converted to natural gas or biomass firing; it is also the date on which you must be in compliance with any newly applicable standards.

§ 63.10001 [Removed and Reserved]

■ 7. Section 63.10001 is removed and reserved.

■ 8. Section 63.10005 is amended by:

■ a. Revising paragraphs (a) introductory text, (a)(2) introductory text, (a)(2)(i) and (ii), and (b)(4);

■ b. Adding paragraph (b)(6);

■ c. Revising paragraphs (d)(3), (d)(4)(i), (f), (h) introductory text, (h)(3) introductory text, (h)(3)(i)(D), and (h)(3)(iii) introductory text; and

■ d. Removing paragraphs (i)(4)(iii) and (iv).

The revisions and additions read as follows:

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) *General requirements.* For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (*e.g.,* a heat input-based limit in lb/MMBtu and a gross output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of data, *e.g.,* hourly gross output data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the date in paragraph (f) of this section for tune-up work practices for existing EGUs; the date that compliance must be demonstrated, as given in § 63.9984 for other requirements for existing EGUs; and in paragraph (g) of this section for all requirements for new EGUs.

* * * * *

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (*i.e.,* an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test shall consist of 30- or, for certain coal-fired existing EGUs that use emissions averaging for Hg, 90-boiler operating days. If the CMS is certified prior to the compliance date (or, if applicable, the approved extended compliance date), the test shall begin with the first operating day on or after that date, except as otherwise provided in paragraph (b) of this section. If the CMS is not certified prior to the compliance

date, the test shall begin with the first operating day after certification testing is successfully completed. In all cases, the initial 30- or 90- operating day averaging period must be completed on or before the date that compliance must be demonstrated (*i.e.,* 180 days after the applicable compliance date).

(i) The CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO_2 emissions limit in Table 1 or 2 to this subpart.

(ii) You must collect hourly data from auxiliary monitoring systems (*i.e.,* stack gas flow rate, CO_2, O_2, or moisture, as applicable) during the performance test period, in order to convert the pollutant concentrations to units of the standard. If you choose to comply with a gross output-based emission limit, you must also collect hourly gross output data during the performance test period.

* * * * *

(b) * * *

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (*e.g.,* stack flow rate, diluent gas concentrations, hourly gross outputs) is available for the entire performance test period; and

* * * * *

(6) For performance stack test data that are collected prior to the date that compliance must be demonstrated and are used to demonstrate initial compliance with applicable emissions limits, the interval for subsequent stack tests begins on the date that compliance must be demonstrated.

* * * * *

(d) * * *

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30- (or 90-) boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) * * *

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

* * * * *

(f) For an existing EGU without a neural network, a tune-up, following the procedures in § 63.10021(e), must occur within 6 months (180 days) after April 16, 2015. For an existing EGU with a neural network, a tune-up must occur within 18 months (545 days) after April 16, 2016. If a tune-up occurs prior to April 16, 2015, you must keep records showing that the tune-up met all rule requirements.

* * * * *

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may pursue this compliance option unless prohibited pursuant to § 63.10000(c)(1)(i).

* * * * *

(3) For Hg, you must conduct a 30- (or 90-) boiler operating day performance test using Method 30B in appendix A–8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within 10 percent of the duct area centered about the duct's centroid at a location that meets Method 1 in appendix A–1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30- (or 90-) boiler operating day test period. You may use a pair of sorbent traps to sample the stack gas for a period consistent with that given in section 5.2.1 of appendix A to this subpart. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures). As an alternative to constant rate sampling per Method 30B, you may use proportional sampling per section 8.2.2 of Performance Specification 12 B in appendix B to part 60 of this chapter.

(i) * * *

(D) Hourly gross output data (megawatts), from facility records.

* * * * *

(iii) Calculate the average Hg concentration, in µg/m³ (dry basis), for the 30- (or 90-) boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO_2 or O_2 concentration, stack gas flow rate, stack gas moisture content, and gross output for the test period. Then:

* * * * *

■ 9. Section 63.10006 is amended by revising paragraph (f) and removing paragraph (j) to read as follows:

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

* * * * *

(f) *Time between performance tests.* (1) Notwithstanding the provisions of § 63.10021(d)(1), the requirements listed in paragraphs (g) and (h) of this section, and the requirements of paragraph (f)(3) of this section, you must complete performance tests for your EGU as follows:

(i) At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter;

(ii) For annual testing:

(A) At least 320 calendar days, measured from the test's end date, must separate performance tests;

(B) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests;

(C) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90-boiler operating day LEE tests; and

(iii) At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years.

(2) For units demonstrating compliance through quarterly emission testing, you must conduct a performance test in the 4th quarter of a calendar year if your EGU has skipped performance tests in the first 3 quarters of the calendar year.

(3) If your EGU misses a performance test deadline due to being inoperative and if 168 or more boiler operating hours occur in the next test period, you must complete an additional performance test in that period as follows:

(i) At least 15 calendar days must separate two performance tests conducted in the same quarter.

(ii) At least 107 calendar days must separate two performance tests conducted in the same calendar year.

(iii) At least 350 calendar days must separate two performance tests conducted in the same 3 year period.

* * * * *

■ 10. Section 63.10007 is amended by revising paragraph (f)(2) to read as follows:

§ 63.10007 What methods and other procedures must I use for the performance tests?

* * * * *

(f) * * *

(2) *Default gross output.* If you use CEMS to continuously monitor Hg, HCl, HF, SO_2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default value is available for use in the emission rate calculations during startup periods or shutdown periods (as defined in § 63.10042). For the purposes of this subpart, this default value is not considered to be substitute data. For a startup or shutdown hour in which there is heat input to an affected EGU but zero gross output, you must calculate the pollutant emission rate using a value equivalent to 5% of the maximum sustainable gross output, expressed in megawatts, as defined in section 6.5.2.1(a)(1) of appendix A to part 75 of this chapter. This default gross output is either the nameplate capacity of the EGU or the highest gross output observed in at least four representative quarters of EGU operation. For a monitored common stack, the default gross output is used only when all EGUs are operating (*i.e.,* combusting fuel) are in startup or shutdown mode, and have zero electrical generation. Under those conditions, a default gross output equal to 5% of the combined maximum sustainable gross output of the EGUs that are operating but have a total of zero gross output must be used to calculate the hourly gross output-based pollutant emissions rate.

* * * * *

■ 11. Section 63.10009 is amended by revising paragraphs (a)(2) introductory text, (a)(2)(i), (b)(1) through (3), (e), (f) introductory text, (f)(2), (g), (j)(1)(ii), and (j)(2) introductory text to read as follows:

§ 63.10009 May I use emissions averaging to comply with this subpart?

(a) * * *

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the ''unit designed for coal ≥8,300 Btu/lb'' subcategory are equal to or less than 1.2 lb/TBtu or 1.3E–2 lb/GWh on a 30-boiler operating day basis or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the ''unit designed for coal ≥ 8,300 Btu/lb'' subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance (LEE) testing. The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E–2 lb/GWh) from EGUs in the ''unit designed for coal ≥ 8,300 Btu/lb'' subcategory is 90-boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance (LEE) testing. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group operates on each of the 30 or 90 days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant).

* * * * *

(b) * * *

(1) *Group eligibility equations.*

$$WAER_m = \frac{\left[\sum_{j=1}^{p} Herm_j \times Rmm_j\right] + \sum_{k=1}^{m} Ter_k \times Rmt_k}{\left(\sum_{j=1}^{p} Rmm_j\right) + \sum_{k=1}^{m} Rmt_k} \qquad (Eq. 1a)$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = hourly emission rate (*e.g.,* lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = number of EGUs in emissions averaging group that rely on CEMS,

Ter_k = Emissions rate (lb/MMBTU or lb/MWh) as determined during the initial compliance determination of EGU k,

Rmt_k = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU k, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum \left[\left(\sum_{j=1}^{p} Herm_{i,j}\right) \times Smm_j \times Cfm_{j_j}\right] + \sum_{k=1}^{m} Ter_k \times Smt_k \times Cft_k}{\sum \left[\sum_{j=1}^{p} Smm_j \times Cfm_j\right] + \sum_{k=1}^{m} Smt_k \times Cft_k} \qquad (Eq.\ 1b)$$

Where:

Variables with the similar names share the descriptions for Equation 1a of this section,

Smm_j = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = conversion factor, calculated from the most recent compliance test results, in terms units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU j,

Smt_k = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = conversion factor, calculated from the most recent compliance test results, in terms units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

(2) Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use Equation 2a or 2b of this section to calculate the 30 day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq. 2a)$$

Where:

Her_i = hourly emission rate (*e.g.,* lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hours that hourly rates are collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq. 2b)$$

Where:

variables with similar names share the descriptions for Equation 2a of this section,

Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the ''coal-fired unit not low rank virgin coal'' subcategory. Use Equation 3a or 3b of this section to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq. 3a)$$

Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hours that hourly rates are collected over the 90-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 90-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq. 3b)$$

Where:

variables with similar names share the descriptions for Equation 2a of this section,

Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

* * * * *

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the date that you begin emissions averaging.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing your emissions averaging plan, you must conduct required emissions monitoring for 30- (or 90-) days of boiler operation and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with this section. If, before the start of your initial compliance demonstration, the Administrator becomes aware that you intend to use emissions averaging for that demonstration, or if your initial Notification of Compliance Status (NOCS) indicates that you intend to implement emissions averaging at a future date, the Administrator may require you to submit your proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

* * * * *

(2) If you are not capable of monitoring heat input or gross output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of paragraph (b) of this section as an alternative to using Equation 1a of paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to paragraphs (g)(1) and (2) of this section. The first averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that you begin emissions averaging.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

* * * * *

(j) * * *

(1) * * *

(ii) The process weighting parameter (heat input, gross output, or steam generated) that will be monitored for each averaging group;

* * * * *

(2) If, as described in paragraph (f) of this section, the Administrator requests you to submit the averaging plan for review and approval, you must receive approval before initiating emissions averaging.

* * * * *

■ 12. Section 63.10010 is amended by revising paragraphs (a)(4), (f)(3) and (4), (h)(6)(i) and (ii), (i)(5)(i)(A) and (B), (j)(1)(i), (j)(4)(i)(A) and (B), and (l) to read as follows:

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) * * *

(4) *Unit with a main stack and a bypass stack that exhausts to the atmosphere independent of the main stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack. If it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall:

(i) Route the exhaust from the bypass through the main stack and its monitoring so that bypass emissions are measured; or

(ii) Install a CEMS only on the main stack and count hours that the bypass stack is in use as hours of deviation from the monitoring requirements.

* * * * *

(f) * * *

(3) Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO_2 emission rates in the 30 boiler operating day period.

(4) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values. For startup or shutdown hours (as defined in § 63.10042) the default gross output and the diluent cap are available for use in the hourly SO_2 emission rate calculations, as described in § 63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default gross output is used to calculate the SO_2 emission rate for any of these hours.

* * * * *

(h) * * *

(6) * * *

(i) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of output data from the PM CPMS. You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of § 63.10031(b);

(ii) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods in your annual deviation report;

* * * * *

(i) * * *

(5) * * *

(i) * * *

(A) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (*e.g.,* calibrations, certain audits). You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of § 63.10031(b);

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods in your annual deviation report;

* * * * *

(j) * * *

(1)(i) Install, calibrate, operate, and maintain your HAP metals CEMS according to your CMS quality control program, as described in § 63.8(d)(2). The reportable measurement output from the HAP metals CEMS must be expressed in units of the applicable emissions limit (*e.g.,* lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

* * * * *

(4) * * *

(i) * * *

(A) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (*e.g.,* calibrations, certain audits). You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of § 63.10031(b);

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of § 63.10031(b);

* * * * *

(l) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with § 63.10020(e).

(1) You shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods.

(2) You shall submit the site-specific monitoring plan upon request by the Administrator.

(3) The provisions of the monitoring plan must address the following items:

(i) Monitoring system installation;

(ii) Performance and equipment specifications;

(iii) Schedule for initial and periodic performance evaluations;

(iv) Performance evaluation procedures and acceptance criteria;

(v) On-going operation and maintenance procedures; and

(vi) On-going recordkeeping and reporting procedures.

(4) You may rely on monitoring system specifications or instructions or manufacturer's specifications to address paragraphs (l)(3)(i) through (vi) of this section.

(5) You must operate and maintain the monitoring system according to the site-specific monitoring plan.

■ 13. Section 63.10011 is amended by revising paragraphs (b), (c), (e), and (g) to read as follows:

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

* * * * *

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired EGU, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with § 63.10007 and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.,* tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (*e.g.,* Hg or HCl) directly, the initial performance test, shall consist of a 30-boiler operating day (or, for certain coal-fired, existing EGUs that use emissions averaging for Hg, a 90-boiler operating day) rolling average emissions rate obtained with a certified CEMS or sorbent trap system, expressed in units of the standard. If the monitoring system is certified prior to the applicable compliance date, the initial averaging period shall either begin with: The first boiler operating day on or after the compliance date; or 30 (or, if applicable, 90) boiler operating days prior to that date, as described in § 63.10005(b). In all cases, the initial 30- or 90-boiler operating day averaging period must be completed on or before the date that compliance must be demonstrated, in accordance with § 63.9984(f). Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For an EGU that uses a CEMS to measure SO_2 or PM emissions for initial compliance, the initial performance test shall consist of a 30-boiler operating day average emission rate obtained with certified CEMS, expressed in units of the standard. If the monitoring system is certified prior to the applicable compliance date, the initial averaging period shall either begin with: The first boiler operating day on or after the compliance date; or 30 boiler operating days prior to that date, as described in § 63.10005(b). In all cases, the initial 30-boiler operating day averaging period must be completed on or before the date that compliance must be demonstrated, in accordance with § 63.9984(f). Initial compliance is demonstrated if the results of the performance test meet the applicable SO_2 or PM emission limit in Table 1 or 2 to this subpart.

* * * * *

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, in accordance with § 63.10030(e).

* * * * *

(g) You must follow the startup or shutdown requirements as established in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default gross output values, as described in § 63.10007(f), during startup periods or shutdown periods.

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

(3) You must report the information as required in § 63.10031.

(4) If you choose to use paragraph (2) of the definition of ''startup'' in § 63.10042 and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of ''startup'' in § 63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below.

(i) As mentioned in § 63.6(g)(1), your request will be published in the **Federal Register** for notice and comment rulemaking. Until promulgation in the **Federal Register** of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of ''startup'' in § 63.10042. You shall not implement the alternative non-opacity emissions standard until promulgation in the **Federal Register** of the final alternative non-opacity emission standard.

(ii) Your request need not address the items contained in § 63.6(g)(2).

(iii) Your request shall provide evidence of a documented manufacturer-identified safety issue.

(iv) Your request shall provide information to document that the PM control device is adequately designed and sized to meet the PM emission limit applicable to the EGU.

(v) In addition, your request shall contain documentation that:

(A) Your EGU is using clean fuels to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity, to bring your EGU and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel in your EGU;

(B) You have followed explicitly your EGU manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) You have identified with specificity the details of your EGU manufacturer's statement of concern.

(vi) Your request shall specify the other work practice standards you will take to limit HAP emissions during startup periods and shutdown periods to ensure a control level consistent with the work practice standards of the final rule.

(vii) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

■ 14. Section 63.10020 is amended by revising paragraph (e) to read as follows:

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

* * * * *

(e) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU.

(1) During each period of startup, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of startup begins;

(ii) The quantity and heat input of clean fuel for each hour of startup;

(iii) The gross output for each hour of startup;

(iv) The date and time that non-clean fuel combustion begins; and

(v) The date and time that clean fuels being combusted for the purpose of startup ends.

(2) During each period of shutdown, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of shutdown begins;

(ii) The quantity and heat input of clean fuel for each hour of shutdown;

(iii) The gross output for each hour of shutdown;

(iv) The date and time that non-clean fuel combustion ends; and

(v) The date and time that clean fuels being combusted for the purpose of shutdown ends.

(3) For PM or non-mercury HAP metals work practice monitoring during startup periods, you must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10010(l).

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CEMS, you must:

(A) Record temperature and combustion air flow or calculated flow as determined from combustion equations of post-combustion (exhaust) gas, as well as amperage of forced draft fan(s), upstream of the filterable PM control devices during each hour of startup.

(B) Record temperature and flow of exhaust gas, as well as amperage of any induced draft fan(s), downstream of the filterable PM control devices during each hour of startup.

(C) For an EGU with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(D) For an EGU with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(E) For an EGU with a wet scrubber needed for filterable PM control, record the scrubber liquid to flue gas ratio and the pressure drop across the scrubber during each hour of startup.

(ii) [Reserved]

■ 15. Section 63.10021 is amended by revising paragraphs (d)(3), (e) introductory text, (e)(9), and (h)(1) to read as follows:

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

* * * * *

(d) * * *

(3) Must conduct site-specific monitoring using CMS to demonstrate compliance with the site-specific monitoring requirements in Table 7 to this subpart pertaining to HCl and HF emissions from a liquid oil-fired EGU to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of § 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in § 63.10020.

(e) Conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section. For your first tune-up, you may perform the burner inspection any time prior to the tune-up or you may delay the first burner inspection until the next scheduled EGU outage provided you meet the requirements of § 63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months. If your EGU is offline when a deadline to perform the tune-up passes, you shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit.

* * * * *

(9) Report the dates of the initial and subsequent tune-ups in hard copy, as specified in § 63.10031(f)(5), until April 16, 2017. After April 16, 2017, report the date of all tune-ups electronically, in accordance with § 63.10031(f). The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of this section are completed.

* * * * *

(h) * * *

(1) You may use the diluent cap and default gross output values, as described in § 63.10007(f), during startup periods or shutdown periods.

* * * * *

■ 16. Section 63.10023 is amended by removing and reserving paragraph (b)(1) and revising paragraph (b)(2) introductory text to read as follows:

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

* * * * *

(b) * * *

(2) Determine your operating limit as follows:

* * * * *

■ 17. Section 63.10030 is amended by:

■ a. Revising paragraphs (e)(1) and (e)(7)(i);

■ b. Adding paragraph (e)(7)(iii);

■ c. Revising paragraph (e)(8); and

■ d. Adding paragraph (f).

The revisions and additions read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(e) * * *

(1) A description of the affected source(s), including identification of the subcategory of the source, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a

petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

* * * * *

(7) * * *

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with § 63.10005(h)(1)(i), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in § 63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

* * * * *

(iii) For each of your existing EGUs, identification of each emissions limit as specified in Table 2 to this subpart with which you plan to comply.

(A) You may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:

(*1*) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current and proposed emission limit;

(*2*) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(*3*) Your request demonstrates through performance stack test results completed within 30 days prior to your submission, compliance for each EGU or EGU emissions averaging group with both the mass per heat input and mass per gross output limits;

(*4*) You revise and submit all other applicable plans, *e.g.,* monitoring and emissions averaging, with your request; and

(*5*) You maintain records of all information regarding your choice of emission limits.

(B) You begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch.

(C) From submission of your request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, you demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each EGU or EGU emissions averaging group.

(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of ‘‘startup’’ in § 63.10042.

(i) Should you choose to rely on paragraph (2) of the definition of ‘‘startup’’ in § 63.10042 for your EGU, you shall include a report that identifies:

(A) The original EGU installation date;

(B) The original EGU design characteristics, including, but not limited to, fuel mix and PM controls;

(C) Each design PM control device efficiency established during performance testing or while operating in periods other than startup and shutdown periods;

(D) The design PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds PM per hour established during performance testing or while operating in periods other than startup and shutdown periods;

(E) The design time from start of fuel combustion to necessary conditions for each PM control device startup;

(F) Each design PM control device efficiency upon startup of the PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(G) Current EGU PM producing characteristics, including, but not limited to, fuel mix and PM controls, if different from the characteristics provided in paragraph (e)(8)(i)(B) of this section;

(H) Current PM control device efficiency from each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(I) Current PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds per hour, if different from the rate provided in paragraph (e)(8)(i)(D) of this section;

(J) Current time from start of fuel combustion to conditions necessary for each PM control device startup, if different from the time provided in paragraph (e)(8)(i)(E) of this section; and

(K) Current PM control device efficiency upon startup of each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(H) of this section.

(ii) The report shall be prepared, signed, and sealed by a professional engineer licensed in the state where your EGU is located.

(iii) You may switch from paragraph (1) of the definition of ‘‘startup’’ in § 63.10042 to paragraph (2) of the definition of ‘‘startup’’ (or vice-versa), provided that:

(A) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current definition of ‘‘startup’’ relied on and the proposed definition you plan to rely on;

(B) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(C) You revise and submit all other applicable plans, *e.g.,* monitoring and emissions averaging, with your submission;

(D) You maintain records of all information regarding your choice of the definition of ‘‘startup’’; and

(E) You begin to use the revised definition of ‘‘startup’’ in the next reporting period after receipt of written acknowledgement from the Administrator of the switch.

(f) You must submit the notifications in § 63.10000(h)(2) and (i)(2) that may apply to you by the dates specified.

■ 18. Section 63.10031 is amended by revising paragraphs (c) introductory text and (c)(4) and (5) and adding paragraphs (c)(6), (7), (8), and (9) to read as follows:

§ 63.10031 What reports must I submit and when?

* * * * *

(c) The compliance report must contain the information required in paragraphs (c)(1) through (9) of this section.

* * * * *

(4) Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in § 63.10021(e)(6) and (7) were completed.

(5) Should you choose to rely on paragraph (2) of the definition of ‘‘startup’’ in § 63.10042 for your EGU, for each instance of startup or shutdown you shall:

(i) Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of § 63.10032(f).

(ii) Include the information required to be monitored, collected, or recorded according to the requirements of § 63.10020(e).

(iii) If you choose to use CEMS to demonstrate compliance with numerical limits, include hourly average CEMS values and hourly average flow values during startup periods or shutdown periods. Use units of milligrams per cubic meter for PM CEMS values, micrograms per cubic meter for Hg CEMS values, and ppmv for HCl, HF, or

SO_2 CEMS values. Use units of standard cubic meters per hour on a wet basis for flow values.

(iv) If you choose to use a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration values in terms of micrograms per cubic meter.

(v) If you choose to use a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation.

(6) You must report emergency bypass information annually from EGUs with LEE status.

(7) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If you are conducting stack tests once every 3 years to maintain LEE status, consistent with § 63.10006(b), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in § 63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(8) A certification.

(9) If you have a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation.

* * * * *

■ 19. Section 63.10032 is amended by revising paragraph (f) to read as follows:

§ 63.10032 What records must I keep?

* * * * *

(f) Regarding startup periods or shutdown periods:

(1) Should you choose to rely on paragraph (1) of the definition of ‘‘startup’’ in § 63.10042 for your EGU, you must keep records of the occurrence and duration of each startup or shutdown.

(2) Should you choose to rely on paragraph (2) of the definition of ‘‘startup’’ in § 63.10042 for your EGU, you must keep records of:

(i) The determination of the maximum possible clean fuel capacity for each EGU;

(ii) The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and

(iii) The information required in § 63.10020(e).

* * * * *

■ 20. Section 63.10042 is amended by:

■ a. Revising the definitions of ‘‘Coal-fired electric utility steam generating unit,’’ ‘‘Coal refuse,’’ ‘‘Fossil fuel-fired,’’ ‘‘Integrated gasification combined cycle electric utility steam generating unit or IGCC,’’ ‘‘Limited-use liquid oil-fired subcategory,’’ and ‘‘Natural gas-fired electric utility steam generating unit’’;

■ b. Adding, in alphabetical order, definition of ‘‘Neural network or neural net’’; and

■ c. Revising the definition of ‘‘Oil-fired electric utility steam generating unit.’’

The revisions and additions read as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ‘‘fossil fuel-fired’’ that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

* * * * *

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of producing more than 25 MW of electrical output from the combustion of fossil fuels. To be ‘‘capable of combusting’’ fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (*e.g.,* coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

* * * * *

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit meeting the definition of ‘‘fossil fuel-fired’’ that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years in a combined-cycle gas turbine. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. No solid coal or solid oil-derived fuel is directly burned in the unit during operation. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

* * * * *

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor when burning oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing on the first of the month following the compliance date specified in § 63.9984.

* * * * *

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ‘‘fossil fuel-fired’’ that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections.

* * * * *

Neural network or *neural net* for purposes of this rule means an automated boiler optimization system. A neural network typically has the ability to process data from many inputs to develop, remember, update, and enable algorithms for efficient boiler operation.

* * * * *

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

* * * * *

■ 21. Revise Table 1 to subpart UUUUU of part 63 to read as follows:

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits:]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	9.0E-2 lb/MWh [1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 3 dscm per run. For ASTM D6348–03 [2] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal.	a. Filterable particulate matter (PM).	9.0E-2 lb/MWh [1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
	OR		

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits:]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E-2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E-2 lb/MWh[4] 9.0E–2 lb/MWh[5].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E-2 lb/GWh	
	Arsenic (As)	2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	4.0E-2 lb/GWh	
	Cobalt (Co)	4.0E-3 lb/GWh	
	Lead (Pb)	9.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	7.0E-2 lb/GWh	
	Selenium (Se)	3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A–8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	4.0E-1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E-1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E-4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E-2 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	5.0E-4 lb/GWh	
	Cadmium (Cd)	2.0E-4 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-2 lb/GWh	
	Lead (Pb)	8.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	9.0E-2 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	1.0E-4 lb/GWh	For Method 30B at appendix A–8 to part 60 of this chapter sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits:]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	6.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-1 lb/GWh	
	Lead (Pb)	3.0E-2 lb/GWh	
	Manganese (Mn)	1.0E-1 lb/GWh	
	Nickel (Ni)	4.1E0 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run;for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit.	a. Filterable particulate matter (PM).	3.0E-2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	7.0E-4 lb/GWh	
	Chromium (Cr)	6.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	7.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	6.0E-3 lb/GWh	
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E-3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

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[1] Gross output.

[2] Incorporated by reference, see § 63.14.

[3] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2 CEMS installed.

[4] Duct burners on syngas; gross output.

[5] Duct burners on natural gas; gross output.

■ 22. Revise Table 2 to subpart UUUUU of part 63 to read as follows:

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits: [1]]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh[2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh.	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[4]	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A–8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
		OR.	
		1.0E0 lb/TBtu or 1.1E-2 lb/GWh	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh[2].	Collect a minimum of 1 dscm per run.
	OR	OR.	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR.	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits: [1]]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26 at appendix A–8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348–03[3] or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2)[4]	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh[2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E-2 lb/GWh	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-1 lb/TBtu or 1.0E-3 lb/GWh	
	Cadmium (Cd)	1.5E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E-2 lb/GWh	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	5.0E-4 lb/MMBtu or 5.0E-3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh[2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	8.0E-4 lb/MMBtu or 8.0E-3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E-1 lb/GWh	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E-2 lb/GWh	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E-2 lb/GWh	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits: [1]]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E-2 lb/GWh	
	Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 1.0E-2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MMBtu or 4.0E-3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E-4 lb/MMBtu or 7.0E-3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E-2 lb/GWh	
	Beryllium (Be)	6.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E-2 lb/GWh	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E-1 lb/GWh	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E-1 lb/GWh	
	Mercury (Hg)	4.0E-2 lb/TBtu or 4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E-4 lb/MMBtu or 2.0E-3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E-5 lb/MMBtu or 5.0E-4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	8.0E-3 lb/MMBtu or 9.0E-2 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-5 lb/MMBtu or 6.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 7.0E-3 lb/GWh	
	Arsenic (As)	3.0E-1 lb/TBtu or 5.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-2 lb/TBtu or 5.0E-4 lb/GWh	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits: [1]]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Cadmium (Cd)	3.0E-1 lb/TBtu or 4.0E-3 lb/GWh	
	Chromium (Cr)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E-2 lb/GWh	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E-1 lb/GWh	
	Selenium (Se)	1.2E0 lb/Tbtu or 2.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	5.0E-3 lb/MMBtu or 8.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	3.0E-1 lb/MMBtu or 2.0E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.

[2] Gross output.

[3] Incorporated by reference, see § 63.14.

[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

■ 23. Revise Table 3 to subpart UUUUU of part 63 to read as follows:

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS

[As stated in § 63.9991, you must comply with the following applicable work practice standards:]

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU.	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup.	a. You have the option of complying using either of the following work practice standards: (1) If you choose to comply using paragraph (1) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels as defined in § 63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified in § 63.10011(g) and § 63.10021(h) and (i). (2) If you choose to comply using paragraph (2) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup. For startup of an EGU, you must use one or a combination of the clean fuels defined in § 63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in § 63.10020(e). Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits beginning with the hour after startup ends. You must engage and operate your particulate matter control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel.

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS—Continued

[As stated in § 63.9991, you must comply with the following applicable work practice standards:]

If your EGU is . . .	You must meet the following . . .
	You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart that require operation of the control devices. b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods. d. You must collect monitoring data during startup periods, as specified in § 63.10020(a) and (e). You must keep records during startup periods, as provided in §§ 63.10032 and 63.10021(h). You must provide reports concerning activities and startup periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031.
4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in § 63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in § 63.10020(a). You must keep records during shutdown periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031.

■ 24. Revise Table 4 to subpart UUUUU of part 63 to read as follows:

TABLE 4 TO SUBPART UUUUU OF PART 63 — OPERATING LIMITS FOR EGUS

[As stated in § 63.9991, you must comply with the applicable operating limits:]

If you demonstrate compliance using . . .	You must meet these operating limits . . .
PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

■ 25. Revise Table 5 to subpart UUUUU of part 63 to read as follows:

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:[1]]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using . . .[2]
1. Filterable Particulate matter (PM).	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A–1 or A–2 to part 60 of this chapter.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources: [1]]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using . . .[2]
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at appendix A–3 to part 60 of this chapter.
		e. Measure the filterable PM concentration.	Method 5 at appendix A–3 to part 60 of this chapter. For positive pressure fabric filters, Method 5D at appendix A–3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 front half temperature shall be 160° ± 14° C (320° ± 25° F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR.	
	PM CEMS	a. Install, certify, operate, and maintain the PM CEMS.	Performance Specification 11 at appendix B to part 60 of this chapter and Procedure 2 at appendix F to part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals.	Emissions Testing	a. Select sampling ports location and the number of traverse points..	Method 1 at appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at appendix A–3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration.	Method 29 at appendix A–8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at appendix A–8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF).	Emissions Testing	a. Select sampling ports location and the number of traverse points..	Method 1 at appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at appendix A–3 to part 60 of this chapter.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources: [1]]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using . . .[2]
		e. Measure the HCl and HF emissions concentrations.	Method 26 or Method 26A at appendix A–8 to part 60 of this chapter or Method 320 at appendix A to part 63 of this chapter or ASTM 6348–03[3] with (1) the following conditions when using ASTM D6348–03: (A) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; (B) For ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5); (C) For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be $70\% \geq R \leq 130\%$; and

3.e.1(D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} x\,100$$

and

To conduct a performance test for the following pollutant . . . (cont'd)	Using . . . (cont'd)	You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont'd)	Using . . .[2] (cont'd)
			(2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR.	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS.	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at appendix A–1 to part 60 of this chapter or Method 30B at Appendix A–8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at appendix A–1 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]

To conduct a performance test for the following pollutant . . . (cont'd)	Using . . . (cont'd)	You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont'd)	Using . . .² (cont'd)
		d. Measure the moisture content of the stack gas.	Method 4 at appendix A–3 to part 60 of this chapter.
		e. Measure the Hg emission concentration.	Method 30B at appendix A–8 to part 60 of this chapter, ASTM D6784,³ or Method 29 at appendix A–8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR.	
	Hg CEMS	a. Install, certify, operate, and maintain the CEMS.	Sections 3.2.1 and 5.1 of appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of appendix A to this subpart.
	OR	OR.	
	Sorbent trap monitoring system.	a. Install, certify, operate, and maintain the sorbent trap monitoring system.	Sections 3.2.2 and 5.2 of appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of appendix A to this subpart.
	OR	OR.	
	LEE testing	a. Select sampling ports location and the number of traverse points.	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at appendix A–1 to part 60 of this chapter or Method 30B at Appendix A–8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G, or 2H at appendix A–1 or A–2 to part 60 of this chapter or flow monitoring system certified per appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at appendix A–1 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981,³ or diluent gas monitoring systems certified according to part 75 of this chapter.
		d. Measure the moisture content of the stack gas.	Method 4 at appendix A–3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration.	Method 30B at appendix A–8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.,* per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold.	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.

To conduct a performance test for the following pollutant . . . (cont'd)	Using . . . (cont'd)	You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont'd)	Using . . .[2] (cont'd)
5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS.	Part 75 of this chapter and § 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).

[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and 63.10021(h).

[2] See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

[3] Incorporated by reference, see § 63.14.

■ 26. Revise Table 6 to subpart UUUUU of part 63 to read as follows:

TABLE 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits:]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an EGU.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

■ 27. Revise Table 8 to subpart UUUUU of part 63 to read as follows:

TABLE 8 TO SUBPART UUUUU OF PART 63—REPORTING REQUIREMENTS

[As stated in § 63.10031, you must comply with the following requirements:]

You must submit a	The report must contain . . .	You must submit the report . . .
1. Compliance report.	a. Information required in § 63.10031(c)(1) through (9); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and. c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e)..	Semiannually according to the requirements in § 63.10031(b).

■ 28. Revise Table 9 to subpart UUUUU of part 63 to read as follows:

Table 9 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:]

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.
§ 63.6(a), (b)(1) through (5), (b)(7), (c), (f)(2) and (3), (h)(2) through (9), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.6(g)	Compliance with Standards and Maintenance Requirements, Use of an alternative non-opacity emission standard.	Yes. See §§ 63.10011(g)(4) and 63.10021(h)(4) for additional requirements.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes, except (1) for the 60-day notification prior to conducting a performance test in § 63.9(e); instead use a 30-day notification period per § 63.10030(d), (2) the notification of the CMS performance evaluation in § 63.9(g)(1) is limited to RATAs, and (3) the information required per § 63.9(h)(2)(i); instead provide the information required per § 63.10030(e)(1) through (e)(6) and (e)(8).
§ 63.10(a), (b)(1), (c), (d)(1) and (2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) through (ix)	Other CMS requirements	Yes.
§ 63.10(b)(3) and (d)(3) through (5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See § 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§§ 63.13 through 63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:]

Citation	Subject	Applies to subpart UUUUU
§§ 63.1(a)(5),(a)(7) through (9), (b)(2), (c)(3) and (4), (d), 63.6(b)(6), (c)(3) and (4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2) through (4), (c)(9)..	Reserved	No.

■ 29. Appendix A to subpart UUUUU of part 63 is amended by revising paragraphs 3.2.1.2.1, 4.1.1.1, and 4.1.1.3, table A–1, paragraphs 4.1.1.5, 4.1.1.5.2, 5.1.2.1, and 5.1.2.3, table A–2, and paragraphs 5.2.1, 6.2.2.3, and 7.1.8.5 and adding paragraph 7.1.2.6 to read as follows:

Appendix A to Subpart UUUUU of Part 63—Hg Monitoring Provisions

* * * * *

3. Mercury Emissions Measurement Methods

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3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this appendix), and including, but not limited to, Hg gas generators and Hg gas cylinders, shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg^0 and $HgCl_2$ are required. Special reagents and equipment may be needed to prepare the Hg^0 and $HgCl_2$ gas standards (*e.g.,* NIST-traceable solutions of $HgCl_2$ and gas generators equipped with mass flow controllers).

* * * * *

4. Certification and Recertification Requirements

* * * * *

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in paragraphs 3.1.8, 3.1.10, and 3.1.11 of this appendix). Use a NIST-traceable elemental Hg gas standard (as defined in paragraphs 3.1.4 of this appendix) for the test. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. If moisture is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over non-consecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (*i.e.,* resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A–1 of this appendix. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A–1 of this appendix.

* * * * *

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A–1 of this appendix. The SIE must either meet the main performance specification or the alternative specification in Table A–1 of this appendix.

TABLE A–1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR H_g CEMS

For this required certification test . . .	The main performance specification[1] is . . .	The alternate performance specification[1] is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test[2,6] ...	$\lvert R - A\rvert \le 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days..	$\lvert R - A\rvert \le 1.0$ µg/scm	The alternate specification may be used on any day of the test.
Linearity check[3,6]	$\lvert R - A_{avg}\rvert \le 10.0\%$ of the reference gas concentration at each calibration gas level (low, mid, or high)..	$\lvert R - A_{avg}\rvert \le 0.8$ µg/scm	The alternate specification may be used at any gas level.
3-level system integrity check[4]	$\lvert R - A_{avg}\rvert \le 10.0\%$ of the reference gas concentration at each calibration gas level..	$\lvert R - A_{avg}\rvert \le 0.8$ µg/scm	The alternate specification may be used at any gas level.

TABLE A–1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR H_g CEMS—Continued

For this required certification test . . .	The main performance specification[1] is . . .	The alternate performance specification[1] is . . .	And the conditions of the alternate specification are . . .
RATA	20.0% RA	$\lvert RM_{avg} - C_{avg}\rvert + \lvert CC\rvert \leq 0.5$ µg/scm[7].	$RM_{avg} < 2.5$µg/scm
Cycle time test[5]	15 minutes where the stability criteria are readings change by < 2.0% of span *or* by ≤ 0.5 µg/scm, for 2 minutes..		

[1] Note that $\lvert R - A\rvert$ is the absolute value of the difference between the reference gas value and the analyzer reading. $\lvert R - A_{avg}\rvert$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

[2] Use elemental Hg standards; a mid-level or high-level upscale gas may be used.

[3] Use elemental Hg standards.

[4] Use oxidized Hg standards.

[5] Use elemental Hg standards; a high-level upscale gas must be used. The cycle time test is not required for Hg CEMS that use integrated batch sampling; however, those monitoring systems must be capable of recording at least one Hg concentration reading every 15 minutes.

[6] If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors.

[7] Note that $\lvert RM_{avg} - C_{avg}\rvert$ is the absolute difference between the mean reference method value and the mean CEMS value from the RATA; CC is the confidence coefficient from Equation 2–5 of Performance Specification 2 in appendix B to part 60 of this chapter.

* * * * *

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include 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)’’ (incorporated by reference, see § 63.14) and Methods 29, 30A, and 30B in appendix A–8 to part 60 of this chapter. When Method 29 or ASTM D6784–02 is used, paired sampling trains are required and the filterable portion of the sample need not be included when making comparisons to the Hg CEMS results for purposes of a RATA. To validate a Method 29 or ASTM D6784–02 test run, calculate the relative deviation (RD) using Equation A–1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100 \quad (Eq.\ A-1)$$

Where:

RD = Relative Deviation between the Hg concentrations of samples ‘‘a’’ and ‘‘b’’ (percent),

C_a = Hg concentration of Hg sample ‘‘a’’ (µ g/dscm), and

C_b = Hg concentration of Hg sample ‘‘b’’ (µ g/dscm).

* * * * *

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µ g/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS2) including the option to substitute the emission limit value (in this case the equivalent concentration) in the denominator of Equation 2–6 in place of the average RM value when the average emissions for the test are less than 50 percent of the applicable emissions limit. For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A–1 of this appendix.

* * * * *

5. Ongoing Quality Assurance (QA) and Data Validation

* * * * *

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use a NIST-traceable elemental Hg gas standard for these calibrations. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

* * * * *

5.1.2.3 Perform a single-level system integrity check weekly, *i.e.,* once every 7 operating days (see the third column in Table A–2 of this appendix).

* * * * *

TABLE A–2—ON-GOING QA TEST REQUIREMENTS FOR H_g CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test[5]	Daily	• Use either a mid- or high-level gas. • Use elemental Hg • Calibrations are not required when the unit is not in operation..	$\|R - A\| \leq 5.0\%$ of span value *or* $\|R - A\| \leq 1.0$ µg/scm.
Single-level system integrity check.	Weekly[1]	• Use oxidized Hg—either mid- or high-level.	$\|R - A_{avg}\| \leq 10.0\%$ of the reference gas value *or* $\|R - A_{avg}\| \leq 0.8$ µg/scm.
Linearity check *or* 3-level system integrity check.	Quarterly[3]	• Required in each "QA operating quarter"[2] and no less than once every 4 calendar quarters. • 168 operating hour grace period available. • Use elemental Hg for linearity check. • Use oxidized Hg for system integrity check.	$\|R - A_{avg}\ \| \leq 10.0\%$ of the reference gas value, at each calibration gas level *or* $\|R - A_{avg}\| \leq 0.8$ µg/scm.
RATA	Annual[4]	• Test deadline may be extended for "non-QA operating quarters," up to a maximum of 8 quarters from the quarter of the previous test.. • 720 operating hour grace period available.	≤20.0% RA when $C_{avg} \geq 2.5$ µg/scm *or* $\|RM_{avg} - C_{avg}\| + \|CC\| \leq 0.5$ µ*g*µ/scm, if $RM_{avg} < 2.5$ µ*g*/scm.

[1] "Weekly" means once every 7 operating days.
[2] A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.
[3] "Quarterly" means once every QA operating quarter.
[4] "Annual" means once every four QA operating quarters.
[5] If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors.

* * * * *

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B–1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 15 operating days.

* * * * *

6. Data Reductions and Calculations

* * * * *

6.2.2.3 The applicable gross output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30- (or 90-) boiler operating day rolling average basis, except as otherwise provided in § 63.10009(a)(2). Use Equation A–5 of this appendix to calculate the Hg emission rate for each averaging period.

$$\overline{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \quad (Eq.\ A-5)$$

Where:

$\overline{E}_o$ = Hg emission rate for the averaging period (lb/GWh),

E_{ho} = Gross output-based hourly Hg emission rate for unit or stack sampling hour "h" in the averaging period, from Equation A–4 of this appendix (lb/GWh), and

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters. **(Note: Do *not* include non-operating hours with zero emission rates in the average).**

* * * * *

7. Recordkeeping and Reporting

* * * * *

7.1.2.6 The EGUs that constitute an emissions averaging group.

* * * * *

7.1.8.5 If applicable, a code to indicate that the default gross output (as defined in § 63.10042) was used to calculate the Hg emission rate.

* * * * *

■ 30. Appendix B to subpart UUUUU of part 63 is amended by:
■ a. Revising paragraphs 2.1 and 2.3;
■ b. Adding paragraphs 2.3.1 and 2.3.2;
■ c. Revising paragraphs 3.1 and 3.2 and adding paragraph 3.3;
■ d. Adding introductory text to section 5;
■ e. Revising paragraphs 5.1, 5.1.2, 5.2, and 5.3;
■ f. Adding paragraphs 5.4, 5.4.1, 5.4.2, 5.4.2.1, 5.4.2.2, 5.4.2.2.1, 5.4.2.2.2, 5.4.2.3, 5.4.2.3.1, 5.4.2.3.2, 5.4.2.3.3, and 5.4.3; and
■ g. Revising section 8 introductory text and paragraph 9.3.2.

The revisions and additions read as follows:

Appendix B to Subpart UUUUU of Part 63—HCl and HF Monitoring Provisions

* * * * *

2. Monitoring of HCl and/or HF Emissions

2.1 *Monitoring System Installation Requirements.* Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with § 63.10010(a) and either Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems or Performance Specification 18 (PS 18) of appendix B to part 60 of this chapter for HCl CEMS.

* * * * *

2.3 *FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.* The following provisions apply:

2.3.1 PS 15, Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 of appendix B to part 60 of this chapter; or

2.3.2 PS 18, Sections 3.0, 6.0, and 11.0 of appendix B to part 60 of this chapter.

3. Initial Certification Procedures

* * * * *

3.1 If you choose to follow PS 15 of appendix B to part 60 of this chapter, then your HCl and/or HF CEMS must be certified according to PS 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below.

* * * * *

3.2 If you choose to follow PS 18 of appendix B to part 60 of this chapter, then your HCl CEMS must be certified according to PS 18, sections 7.0, 8.0, 11.0, 12.0, and 13.0.

3.3 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

* * * * *

5. On-Going Quality Assurance Requirements

On-going QA test requirements for HCl and HF CEMS must be implemented as follows:

5.1 If you choose to follow Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures of PS 15 shall apply as set forth in sections 5.1.1 through 5.1.3 and 5.4.2 of this appendix.

* * * * *

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, ''quarterly'' means once every ''QA operating quarter'' (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for ''non-QA operating quarters'' (*i.e.,* calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.4.2.2.1 of this appendix.

* * * * *

5.2 If you choose to follow Performance Specification PS 18 of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures in Procedure 6 of appendix F to part 60 of this chapter shall apply. The quarterly and annual QA tests required under Procedure 6 shall be performed, respectively, at the frequencies specified in sections 5.1.2 and 5.1.3 of this appendix.

5.3 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

* * * * *

5.4 *Data Validation.*

5.4.1 *Out-of-Control Periods.* An HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.4.2 *Grace Periods.* For the purposes of this appendix, a ''grace period'' is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.4.2.1 For the monitoring systems described in section 5.3 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.4.2.2 For the purposes of this appendix, if the deadline for a required gas audit/data accuracy assessment or RATA of an HCl CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.4.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit or other quarterly data accuracy assessment; or

5.4.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.4.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.4.2.3.1 For a gas audit or RATA of the monitoring systems described in sections 5.1 and 5.2 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.4.2.3.2 For the gas audit or other quarterly data accuracy assessment of an HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit/data accuracy assessment is required for that quarter.

5.4.2.3.3 For the RATA of an HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.4.3 *Conditional Data Validation.* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, the conditional data validation provisions in § 75.20(b)(3)(ii) through (ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a quarterly gas audit or data accuracy assessment shall be the same as for a linearity check (*i.e.,* 168 unit or stack operating hours).

* * * * *

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

* * * * *

9. Data Reduction and Calculations

* * * * *

9.3.2 For gross output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A–2 or A–3 in appendix A to this subpart (as applicable), replacing the value of K with 9.43×10^{-8} lb/scf-ppm (for HCl) or 5.18×10^{-8} (for HF) and defining C_h as the hourly average HCl or HF concentration in ppm. Then, divide the result by the hourly gross output (megawatts) to convert it to units of lb/MWh. If the gross output is zero during a startup or shutdown hour, use the default gross output (as defined in § 63.10042) to calculate the HCl or HF emission rate. The default gross output is not considered to be a substitute data value.

* * * * *

[FR Doc. 2016–06563 Filed 4–5–16; 8:45 am]

BILLING CODE 6560–50–P

F. Executive Order 13175: Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175, because the SIP is not approved to apply on any Indian reservation land or in any other area where the EPA or an Indian tribe has demonstrated that a tribe has jurisdiction, and will not impose substantial direct costs on tribal governments or preempt tribal law. Thus, Executive Order 13175 does not apply to this action.

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

The EPA interprets Executive Order 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 Executive Order. This action is not subject to Executive Order 13045 because it does not impose additional requirements beyond those imposed by state law.

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

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

Section 12(d) of the NTTAA directs the EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. The EPA believes that this action is not subject to the requirements of section 12(d) of the NTTAA because application of those requirements would be inconsistent with the CAA.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Population

The EPA lacks the discretionary authority to address environmental justice in this rulemaking.

K. Congressional Review Act (CRA)

This action is subject to the 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).

L. Petitions for Judicial Review

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by July 18, 2016. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements (see section 307(b)(2)).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Approval and promulgation of implementation plans, Incorporation by reference, Oxides of nitrogen, Ozone, and Volatile organic compounds.

Dated: May 6, 2016.

Deborah Jordan,

Acting Regional Administrator, Region IX.

[FR Doc. 2016–11744 Filed 5–18–16; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2013–0696; FRL–9944–26–OAR]

RIN 2060–AS86

Technical Amendments to Performance Specification 18 and Procedure 6

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: The Environmental Protection Agency (EPA) is taking direct final action to make several minor technical amendments to the performance specifications and test procedures for hydrogen chloride (HCl) continuous emission monitoring systems (CEMS). This direct final rule also makes several minor amendments to the quality assurance (QA) procedures for HCl CEMS used for compliance determination at stationary sources. The performance specification (Performance Specification 18) and the QA procedures (Procedure 6) were published in the **Federal Register** on July 7, 2015. These amendments make several minor corrections and clarify several aspects of these regulations.

DATES: This rule is effective on August 17, 2016 without further notice, unless the EPA receives adverse comment by July 5, 2016. If the EPA receives adverse comment, we will publish a timely withdrawal in the **Federal Register** informing the public that the rule will not take effect.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2013–0696, at *http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov.* The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. 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). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

FOR FURTHER INFORMATION CONTACT: Ms. Candace Sorrell, U.S. EPA, Office of Air Quality Planning and Standards, Air Quality Assessment Division, Measurement Technology Group (Mail Code: E143–02), Research Triangle Park, NC 27711; telephone number: (919) 541–1064; fax number: (919) 541–0516; email address: *sorrell.candace@epa.gov.*

SUPPLEMENTARY INFORMATION: The information presented in this rule is organized as follows:

E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act (CRA)

I. General Information

A. Why is the EPA using a direct final rule?

The EPA is publishing this direct final rule without a prior proposed rule because we view this as a non-controversial action and anticipate no adverse comment. This action makes minor technical amendments to Performance Specification 18 (PS 18) and Procedure 6. However, in the ‘‘Proposed Rules’’ section of this **Federal Register**, we are publishing a separate document that will serve as the proposed rule to announce the EPA's intent to amend PS 18 and Procedure 6, if adverse comments are received on this direct final rule by July 5, 2016. We will not institute a second comment period on this action. Any parties interested in commenting must do so at this time. For further information about commenting on this rule, see the **ADDRESSES** section of this document. If the EPA receives adverse comment, the EPA will publish a timely withdrawal in the **Federal Register** informing the public that the rule will not take effect. The EPA will address all public comments in a subsequent final rule based on the proposed rule. Please note that if the EPA receives adverse comment on an amendment, paragraph, or section of this rule and if that provision may be severed from the remainder of the rule, the EPA may adopt as final those provisions of the rule that are not the subject of an adverse comment.

B. Does this action apply to me?

The major entities that would potentially be affected by the final PS 18 and the QA requirements of Procedure 6 for gaseous HCl CEMS are those entities that are required to install a new HCl CEMS, relocate an existing HCl CEMS, or replace an existing HCl CEMS under any applicable subpart of 40 Code of Federal Regulations (CFR) part 60, 61, or 63. Table 1 of this preamble lists the current federal rules by subpart and the corresponding source categories to which the PS 18 and Procedure 6 potentially would apply.

TABLE 1—SOURCE CATEGORIES THAT WOULD POTENTIALLY BE SUBJECT TO PS 18 AND PROCEDURE 6

Subpart(s)	Source category
40 CFR part 63	
Subpart LLL	Portland Cement Manufacturing Industry.
Subpart UUUUU	Coal- and Oil-fired Electric Utility Steam Generating Units.
Subpart DDDDD	Industrial, Commercial, and Institutional Boilers and Process Heaters.

The requirements of PS 18 and Procedure 6 may also apply to stationary sources located in a state, district, reservation, or territory that adopts PS 18 or Procedure 6 in its implementation plan.

Table 2 lists the corresponding North American Industry Classification System (NAICS) codes for the source categories listed in Table 1 of this preamble.

TABLE 2—NAICS FOR POTENTIALLY REGULATED ENTITIES

Industry	NAICS Codes
Fossil Fuel-Fired Electric Utility Steam Generating Units	327310
	[a] 921150
Portland Cement Manufacturing Plants	327310
Industrial, Commercial, and Institutional Boilers and Process Heaters	211
	321
	322
	325
	324
	316, 326, 339
	331
	332
	336
	221
	622
	611

[a] Industry in Indian Country.

Tables 1 and 2 are not intended to be exhaustive, but rather they provide a guide for readers regarding entities potentially affected by this action. If you have any questions regarding the potential applicability of PS 18 and test procedures (Procedure 6) to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

C. What should I consider as I prepare my comments for the EPA?

a. *Submitting CBI.* Do not submit this information to the EPA through *https://www.regulations.gov* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to the EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

b. *Tips for Preparing Your Comments.* When submitting comments, remember to:

- Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).
- Follow directions. The agency may ask you to respond to specific questions or organize comments by referencing a CFR part or section number.
- Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.
- Describe any assumptions and provide any technical information and/or data that you used.
- If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.
- Provide specific examples to illustrate your concerns, and suggest alternatives.
- Explain your views as clearly as possible, avoiding the use of profanity or personal threats.
- Make sure to submit your comments by the comment period deadline identified.

D. Where can I obtain a copy of this action?

In addition to being available in the docket, an electronic copy of this rule will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN) Web site. Following publication, the EPA will post the **Federal Register** version of the promulgation and key technical documents at *http://www3.epa.gov/ttn/emc/propperf.html.*

E. Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of this action must be filed in the United States Court of Appeals for the DC Circuit by July 18, 2016. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. Parties with objections to this direct final rule are encouraged to file a comment in response to the parallel notice of proposed rulemaking for this action published in the proposed rules section of this **Federal Register**, rather than file an immediate petition for judicial review of this direct final rule, so that the EPA can withdraw this direct final rule and address the comment in the proposed rulemaking. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

II. This Action

On July 7, 2015, the EPA promulgated PS 18, that includes requirements for the initial acceptance of CEMS to measure HCl emissions (80 FR 38628). In that same action, we promulgated Procedure 6 specifying the minimum QA requirements necessary for control and assessment of the quality of CEMS data submitted to the EPA. Performance Specification 18 is applicable to the evaluation of HCl continuous monitoring instruments for Portland cement facilities, electric generating units, and industrial, commercial, and institutional boilers and process heaters. After publication of PS 18 and Procedure 6, we identified minor definition inconsistencies and unintended differences between the proposal and the final rule. In this action, we are making corrections to PS 18 and Procedure 6 as noted below to eliminate such inconsistencies and to remove unintended changes that occurred between the notice of proposed rulemaking and the final rulemaking.

This action:

(1) Adds definitions for beam attenuation and beam intensity to clarify the meaning of these terms (Section 3.0);

(2) Clarifies which detection limits must be less than 20 percent of the applicable emission limit (Section 11.5.6.5);

(3) Revises the requirements to determine zero gas calibration drift measurements by allowing either exclusion or inclusion of the measurement optical path (Section 11.8.6.2);

(4) Revises definitions for terms C_i, and S, to make them consistent with other performance specifications (Section 12.1);

(5) Corrects equation 2 in PS 18 to include the average measured concentration of HCl used to calculate CEMS interference. This change clarifies that single or multiple interferent gases are allowed to be evaluated in PS 18 (Section 12.2);

(6) Revises equation 7 in PS 18 to include an additional term that allows correction for the measured native background HCl concentration. This revision permits calculations for either option in revised section 11.8.6.2 (Section 12.4.4);

(7) Corrects appendix A, equation 3 in PS 18 for calculating dilution factors when dynamic spike quality control measurements are made (PS 18 appendix A, Section 11.2.3);

(8) Clarifies, in Procedure 6, that QA for data above span is subject to the specific requirements in applicable rules or permits, that supersede the general requirements in Procedure 6 (Section 4.1.5 and 4.1.5.3);

(9) Resolves, in Procedure 6, prior confusion between greater than two clock hours and greater than two consecutive 1-hour averages in the measurement period for exceedance of span before additional CEMS responses checks are required (Section 4.1.5.1);

(10) Clarifies the units of measure (percent) required for Integrated Path CEMS beam intensity check (Section 4.2.1); and

(11) Corrects the incomplete reference to the equations required to calculate dynamic spiking error (DSE) (Section 5.2.4.2).

III. Statutory and Executive Order Reviews

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

This action is not a significant regulatory action and, therefore, was not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose an information collection burden under the PRA. These changes do not add information collection requirements beyond those currently required under the applicable regulations.

C. 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. This action will not impose any requirements on small entities. This action makes minor technical correction and adds clarification in PS 18 and Procedure 6 and does not impose additional regulatory requirements on sources.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any 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.

E. 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.

F. 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 adds additional language that clarifies several aspects for the performance standard and procedure and corrects some minor technical errors, but does not change the requirements for conducting the test method. Thus, Executive Order 13175 does not apply to this action.

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

The EPA interprets Executive Order 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 Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

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

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

I. National Technology Transfer and Advancement Act

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. This action does not relax the control measures on sources regulated by the rule and, therefore, will not cause emissions increases from these sources.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective August 17, 2016.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Continuous emission monitoring systems, Hydrogen chloride, Performance specifications, Test methods and procedures.

Dated: May 2, 2016.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I of the Code of Federal Regulations is amended 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.*

■ 2. In appendix B to part 60, Performance Specification 18:

■ a. Revise Sections 3.1 through 3.23, 11.5.6.5, 11.8.6.2, 12.1, 12.2 and 12.4.4;

■ b. Add Sections 3.24, 3.25, and 12.2.1; and

■ c. Revise Section 11.2.3 in appendix A of Performance Specification 18.

The revisions and additions read as follows:

Appendix B to Part 60—Performance Specifications

*   *   *   *   *

PERFORMANCE SPECIFICATION 18–PERFORMANCE SPECIFICATIONS AND TEST PROCEDURES FOR GASEOUS HYDROGEN CHLORIDE (HCl) CONTINUOUS EMISSION MONITORING SYSTEMS AT STATIONARY SOURCES

*   *   *   *   *

3.0 *Definitions*

3.1 *Beam attenuation* is the reduction in electromagnetic radiation (light) throughput from the maximum beam intensity experienced during site specific CEMS operation.

3.2 *Beam intensity* is the electromagnetic radiation (light) throughput for an IP–CEMS instrument measured following manufacturers specifications.

3.3 *Calibration cell* means a gas containment cell used with cross stack or integrated path (IP) CEMS for calibration and to perform many of the test procedures required by this performance specification. The cell may be a removable sealed cell or an evacuated and/or purged cell capable of exchanging reference and other calibration gases as well as zero gas standards. When charged, it contains a known concentration of HCl and/or interference gases. The calibration cell is filled with zero gas or removed from the optical path during stack gas measurement.

3.4 *Calibration drift* (CD) means the absolute value of the difference between the CEMS output response and an upscale reference gas or a zero-level gas, expressed as a percentage of the span value, when the CEMS is challenged after a stated period of operation during which no unscheduled adjustments, maintenance or repairs took place.

3.5 *Centroidal area* means a central area that is geometrically similar to the stack or duct cross section and is no greater than 10 percent of the stack or duct cross-sectional area.

3.6 *Continuous Emission Monitoring System* (CEMS) means the total equipment required to measure the pollutant concentration or emission rate continuously. The system generally consists of the following three major subsystems:

3.6.1 *Sample interface* means that portion of the CEMS used for one or more of the following: Sample acquisition, sample transport, sample conditioning, defining the optical measurement path, and protection of the monitor from the effects of the stack effluent.

3.6.2 *HCl analyzer* means that portion of the HCl CEMS that measures the total vapor phase HCl concentration and generates a proportional output.

3.6.3 *Data recorder* means that portion of the CEMS that provides a permanent electronic record of the analyzer output. The data recorder may record other pertinent data such as effluent flow rates, various instrument temperatures or abnormal CEMS operation. The data recorder may also include automatic data reduction capabilities and CEMS control capabilities.

3.7 *Diluent gas* means a major gaseous constituent in a gaseous pollutant mixture. For combustion sources, either carbon dioxide (CO_2) or oxygen (O_2) or a combination of these two gases are the major gaseous diluents of interest.

3.8 *Dynamic spiking* (DS) means the procedure where a known concentration of HCl gas is injected into the probe sample gas stream for extractive CEMS at a known flow rate to assess the performance of the measurement system in the presence of potential interference from the flue gas sample matrix.

3.9 *Independent measurement(s)* means the series of CEMS data values taken during sample gas analysis separated by two times the procedure specific response time (RT) of the CEMS.

3.10 *Integrated path CEMS* (IP–CEMS) means an in-situ CEMS that measures the gas concentration along an optical path in the stack or duct cross section.

3.11 *Interference* means a compound or material in the sample matrix other than HCl whose characteristics may bias the CEMS measurement (positively or negatively). The interference may not prevent the sample measurement, but could increase the analytical uncertainty in the measured HCl concentration through reaction with HCl or by changing the electronic signal generated during HCl measurement.

3.12 *Interference test* means the test to detect CEMS responses to interferences that are not adequately accounted for in the calibration procedure and may cause measurement bias.

3.13 *Level of detection* (LOD) means the lowest level of pollutant that the CEMS can detect in the presence of the source gas matrix interferents with 99 percent confidence.

3.14 *Liquid evaporative standard* means a reference gas produced by vaporizing National Institute of Standards and Technology (NIST) traceable liquid standards of known HCl concentration and quantitatively diluting the resultant vapor with a carrier gas.

3.15 *Measurement error* (ME) is the mean difference between the concentration measured by the CEMS and the known concentration of a reference gas standard, divided by the span, when the entire CEMS, including the sampling interface, is challenged.

3.16 *Optical path* means the route light travels from the light source to the receiver used to make sample measurements.

3.17 *Path length* means, for an extractive optical CEMS, the distance in meters of the optical path within a gas measurement cell. For an IP–CEMS, path length means the distance in meters of the optical path that passes through the source gas in the stack or duct.

3.18 *Point CEMS* means a CEMS that measures the source gas concentration, either at a single point at the sampling probe tip or over a path length for IP–CEMS less than 10 percent of the equivalent diameter of the stack or duct cross section.

3.19 *Stack pressure measurement device* means a NIST-traceable gauge or monitor that measures absolute pressure and conforms to the design requirements of ASME B40.100–2010, ''Pressure Gauges and Gauge Attachments'' (incorporated by reference—see § 60.17).

3.20 *Reference gas standard* means a NIST-traceable gas standard containing a known concentration of HCl certified in accordance with an EPA traceability protocol in section 7.1 of this PS.

3.21 *Relative accuracy* (RA) means the absolute mean difference between the gas concentration or the emission rate determined by the CEMS and the value determined by the RM, plus the confidence coefficient of a series of nine test runs, divided by the average of the RM or the applicable emission standard.

3.22 *Response time* (RT) means the time it takes for the measurement system, while operating normally at its target sample flow rate, dilution ratio, or data collection rate to respond to a known step change in gas concentration, either from a low- or zero-level to a high-level gas concentration or from a high-level to a low or zero-level gas concentration, and to read 95 percent of the change to the stable instrument response. There may be several RTs for an instrument related to different functions or procedures (*e.g.,* DS, LOD, and ME).

3.23 *Span value* means an HCl concentration approximately equal to two times the concentration equivalent to the emission standard unless otherwise specified in the applicable regulation, permit or other requirement. Unless otherwise specified, the span may be rounded up to the nearest multiple of 5.

3.24 *Standard addition* means the addition of known amounts of HCl gas (either statically or dynamically) to the actual measurement path or measured sample gas stream.

3.25 *Zero gas* means a gas or liquid with an HCl concentration that is below the LOD of the measurement system.

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11.0 *Performance Specification Test Procedure*

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11.5.6.5 If your system LOD field verification does not demonstrate a SAR greater than or equal to your initial controlled environment LOD, you must increase the SA concentration incrementally and repeat the field verification procedure until the SAR is equal to or greater than LOD. The site-specific standard addition detection level (SADL) is equal to the standard addition needed to achieve the acceptable SAR, and SADL replaces the controlled environment LOD. For extractive CEMS, the SADL is calculated as the ESA using Equation A7 in appendix A of this PS. For IP–CEMS, the SADL is the SA calculated using Equation A8 in appendix A of this PS. As described in section 13.1 of this PS, the LOD or the SADL that replaces an LOD must be less than 20 percent of the applicable emission limit.

* * * * *

11.8.6.2 For IP–CEMS, you must include the source measurement optical path while performing the upscale CD measurement; you may exclude the source measurement optical path when determining the zero gas concentration. Calculate the CD for IP CEMS using equations 4, 5, 6B, and 7 in section 12.4.

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12.0 *Calculations and Data Analysis*

12.1 *Nomenclature*

C_i = Zero or HCl reference gas concentration used for test i (ppmv);
$C_{i,eff}$ = Equivalent concentration of the reference gas value, C_i, at the specified conditions (ppmv);
CC = Confidence coefficient (ppmv);
$CD_{extractive}$ = Calibration drift for extractive CEMS (percent);
CD_{IP} = Calibration drift for IP–CEMS (percent);
CD_0 = Calibration drift at zero HCl concentrations for an IP–CEMS (percent);
d_{avg} = Mean difference between CEMS response and the reference gas (ppmv);
d_i = Difference of CEMS response and the RM value (ppmv);
I = Total interference from major matrix stack gases, (percent);
LSF = Line strength factor for IP–CEMS instrument specific correction for temperature and gas matrix effects derived from the HITRAN and/or manufacturer specific database (unitless);
ΔMC_{avg} = Average of the 3 absolute values of the difference between the measured HCl calibration gas concentrations with and without interference from selected stack gases (ppmv);
MC_i = Measured HCl reference gas concentration i (ppmv);
$\overline{MC}_i$ = Average of the measured HCl reference gas concentration i (ppmv);
MC_{int} = Measured HCl concentration of the HCl reference gas plus the individual or combined interference gases (ppmv);
$ME_{extractive}$ = Measurement error for extractive CEMS (percent);
ME_{IP} = Measurement error for IP–CEMS (percent);
MN_{avg} = Average concentration at all sampling points (ppmv);
MN_{bi} = Measured native concentration bracketing each calibration check measurement (ppmv);
MN_i = Measured native concentration for test or run I (ppmv);
n = Number of measurements in an average value;
P_{stack} = Absolute stack pressure (mm Hg)
$P_{reference}$ = Absolute pressure of the calibration cell for IP–CEMS (mm Hg)
PL_{Cell} = Path length of IP–CEMS calibration cell (m);
PL_{Stack} = Path length of IP–CEMS stack optical path (m);
RA = Relative accuracy of CEMS compared to a RM (percent);
RM_i = RM concentration for test run i (ppmv);
RM_{avg} = Mean measured RM value (ppmv);
S = Span value (ppmv);
S_d = Standard deviation of the differences (ppmv);
S_{ti} = Stratification at traverse point i (percent);
SADL = Standard addition detection level (ppmv);
$t_{0.975}$ = One-sided t-value at the 97.5th percentile obtained from Table 5 in section 17.0 for n–1 measurements;
$T_{reference}$ = Temperature of the calibration cell for IP–CEMS (degrees Kelvin);
T_{stack} = Temperature of the stack at the monitoring location for IP–CEM (degrees Kelvin).

12.2 *Calculate the difference between the measured HCl concentration with and without interferents for each interference gas (or mixture) for your CEMS as:*

$$\Delta MC_{avg} = \frac{\sum_{i=1}^{3} |MC_i - MC_{int}|}{3} \qquad \text{Eq. 1}$$

Calculate the total percent interference as:

$$I = \sum_{i=1}^{n} \frac{\Delta MC_{avg}}{\overline{MC_i}} * 100 \qquad \text{Eq. 2}$$

12.2.1 Calculate the equivalent concentration $C_{i,eff}$ using Equation 4:

$$C_{i,eff} = \left[C_i \times \frac{PL_{cell}}{PL_{Stack}} \times \frac{T_{stack}}{T_{reference}} \times \frac{P_{reference}}{P_{stack}} LSF \right] \qquad \text{Eq. 4}$$

* * * * *

12.4.4 Calculate the zero CD as a percent of span for an IP–CEMS as:

$$CD_0 = \frac{(|(MC_i - MN_b) - (MC_{i+1} - MN_b)|)}{S} * 100 \qquad \text{Eq. 7}$$

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PS–18 Appendix A Standard Addition Procedures

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11.0 *Calculations and Data Analysis.* * * *

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11.2.3 If you determine your spike dilution factor using an independent stable tracer that is present in the native source emissions, calculate the dilution factor for dynamic spiking using equation A3:

$$DF = \frac{M_{spiked\ tracer} - M_{native\ tracer}}{C_{tracer\ spiked} - M_{native\ tracer}} \qquad \text{Eq. A3}$$

* * * * *

■ 3. In appendix F to part 60, revise Sections 4.1.5, 4.1.5.1, 4.1.5.3, and 5.2.4.2 in Procedure 6 to read as follows:

Appendix F to Part 60—Quality Assurance Procedures

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Procedure 6. Quality Assurance Requirements for Gaseous Hydrogen Chloride (HCl) Continuous Emission Monitoring Systems Used for Compliance Determination at Stationary Sources

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4.0 *Daily Data Quality Requirements and Measurement Standardization Procedures*

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4.1.5 Additional Quality Assurance for Data above Span. Unless otherwise specified in an applicable rule or permit, this procedure must be used to assure data quality and may be used when significant data above span is being collected.

4.1.5.1 Any time the average measured concentration of HCl exceeds 150 percent of the span value for two consecutive 1-hour averages, conduct the following ‘above span’ CEMS response check.

* * * * *

4.1.5.3 Unless otherwise specified in an applicable rule or permit, if the ‘above span’ response check is conducted during the period when measured emissions are above span and there is a failure to collect at least one data point in an hour due to the response check duration, then determine the emissions average for that missed hour as the average of hourly averages for the hour preceding the missed hour and the hour following the missed hour

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5.0 *Data Accuracy Assessment*

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5.2.4.2 Calculate results as described in section 6.4. To determine CEMS accuracy you must calculate the dynamic spiking error (DSE) for each of the two upscale audit gases using equation A5 in appendix A to PS–18 and Equation 6–3 in section 6.4 of Procedure 6 in appendix B to this part.

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2014–0853; FRL–9945–82]

Maleic Anhydride; Exemption From the Requirement of a Tolerance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes an exemption from the requirement of a tolerance for residues of maleic anhydride (CAS Reg. No. 108–31–6) when used as an inert ingredient (stabilizer) in pesticide formulations applied to growing crops at a maximum concentration not to exceed 3.5% by weight in the pesticide formulation. Exponent, on behalf of Cheminova A/S, submitted a petition to EPA under the Federal Food, Drug, and Cosmetic Act (FFDCA), requesting an amendment to an existing requirement of a tolerance. This regulation eliminates the need to