ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9 and 60

[EPA–HQ–OAR–2007–0011; FRL–9672–3]

RIN 2060–AN72

Standards of Performance for Petroleum Refineries; Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; lift stay of effective date.

SUMMARY: On June 24, 2008, the EPA promulgated amendments to the Standards of Performance for Petroleum Refineries and new standards of performance for petroleum refinery process units constructed, reconstructed or modified after May 14, 2007. The EPA subsequently received three petitions for reconsideration of these final rules. On September 26, 2008, the EPA granted reconsideration and issued a stay for the issues raised in the petitions regarding process heaters and flares. On December 22, 2008, the EPA addressed those specific issues by proposing amendments to certain provisions for process heaters and flares and extending the stay of these provisions until further notice. The EPA also proposed technical corrections to the rules for issues that were raised in the petitions for reconsideration. In this action, the EPA is finalizing those amendments and technical corrections and is lifting the stay of all the provisions granted on September 26, 2008 and extended until further notice on December 22, 2008.

DATES: The stay of the definition of ''flare'' in 40 CFR 60.101a, paragraph (g) of 40 CFR 60.102a, and paragraphs (d) and (e) of 40 CFR 60.107a is lifted and this final rule is effective on November 13, 2012. The incorporation by reference of certain publications listed in the final rule is approved by the Director of the Federal Register as of November 13, 2012.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2007–0011. 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 (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 in *www.regulations.gov* or in hard copy at the EPA Docket Center, Standards of Performance for Petroleum Refineries Docket, EPA 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 Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Brenda Shine, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, Refining and Chemicals Group (E143–01), Environmental Protection Agency, Research Triangle Park, NC 27711, telephone number: (919) 541–3608; fax number: (919) 541–0246; email address: *shine.brenda@epa.gov.*

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

I. General Information

A. Does this action apply to me?

Categories and entities potentially regulated by these final rules include:

Category	NAICS Code[1]	Examples of regulated entities
Industry	32411	Petroleum refiners.
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 regulated by this action. To determine whether your facility would be regulated by this action, you should examine the applicability criteria in 40 CFR 60.100 and 40 CFR 60.100a. If you have any questions regarding the applicability of this action to a particular entity, contact the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this final action is available on the World Wide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of this final action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at *http://www.epa.gov/ttn/oarpg*. The TTN provides information and technology exchange in various areas of air pollution control.

The EPA has created a redline document comparing the existing regulatory text of 40 CFR part 60, subpart Ja and the final amendments to aid the public's ability to understand the changes to the regulatory text. This document has been placed in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2007–0011).

C. Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of these final rules is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by November 13, 2012. Under section 307(b)(2) of the CAA, the requirements established by these final rules 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] 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, 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.

II. Background Information

A. Executive Summary

1. Purpose of the Regulatory Action

This action finalizes amendments that were proposed on December 22, 2008, to address reconsideration issues related to the promulgation of new source performance standards (NSPS) for flares and process heaters on June 24, 2008. This action also lifts the stay that was granted on September 26, 2008 (73 FR 55751) and extended until further notice on December 22, 2008 (73 FR 78552) on the provisions at issue.

2. Summary of Major Provisions

Table 1 presents a summary of major changes to the rule since it was first promulgated on June 24, 2008. The following discussion is a summary of major provisions of this rule.

TABLE 1—SUMMARY OF MAJOR CHANGES SINCE JUNE 24, 2008, PROMULGATION

Affected source	Aspect	NSPS Ja (June 24, 2008)	NSPS Ja final
All Process Heater NO_X limits	Averaging time	24-hour rolling average	30-day rolling average.
Natural Draft Process Heaters	NO_X Emission Limits	40 ppmv	40 ppmv or 0.04 lb/MM BTU.
Forced Draft Process Heaters	NO_X Emission Limits	40 ppmv	60 ppmv or 0.06 lb/MM BTU.
Forced Draft Process Heaters with Co-fired (oil and gas) Burners.	NO_X Emission Limits	40 ppmv	150 ppmv or Weighted average based on oil at 0.40 lb/MM BTU and gas at 0.11 lb/MM BTU.
Natural Draft Process Heaters with Co-fired (oil and gas) Burners.	NO_X Emission Limits	40 ppmv	150 ppmv or weighted average based on oil at 0.35 lb/MM BTU and gas at 0.06 lb/MM BTU.
Process Heaters	Alternate Emission Standards	None	Case by case approval for some circumstances.
Flares	Applicability	New or reconstructed flare systems or existing flare systems that are physically altered to increase flow or to add new connections.	Similar, except specific list of connections that do not trigger applicability.
Fuel gas combustion devices	H_2S concentration limit	162 ppmv H_2S (3-hour average); 60 ppmv H_2S (annual rolling average).	162 ppmv H_2S (3-hour average); No 60 ppmv H_2S long term concentration limit for flares.
Flares	Compliance date for modified flares.	Comply with H_2S limit at start-up, and all other requirements within 1 year.	Comply with H_2S limit at start-up (except for modified flares not previously subject to the H_2S limit in 40 CFR part 60, subpart J or those with monitoring alternatives, or those complying with subpart J as specified in a consent decree, which comply no later than 3 years) and all other requirements within 3 years.
Flares	Flow limits	Flare system-wide flow limit of 250,000 scfd.	No limits.

TABLE 1—SUMMARY OF MAJOR CHANGES SINCE JUNE 24, 2008, PROMULGATION—Continued

Affected source	Aspect	NSPS Ja (June 24, 2008)	NSPS Ja final
Flares	Root Cause Analysis and Corrective Action (RCA/CA).	RCA/CA required on upsets or malfunctions in excess of 500,000 scfd or 500 lbs/day SO_2 from SSM.	RCA/CA required for 500,000 scfd above base load and 500 lbs SO_2 in any 24-hour period.
Flares	Flow monitoring	Continuous	Continuous except for intermittent/emergency only flares with water seal monitoring and limited releases.
Flares	Sulfur Monitoring	Continuous Total Reduced Sulfur (TRS).	Continuous TRS, using reference method 15A (Total Sulfur).

Affected process heaters are those that were modified, reconstructed or constructed after May 14, 2007. For these affected sources, these final amendments include concentration-based nitrogen oxide (NO_X) emissions limits and alternative heating value-based NO_X emissions limits, both determined daily on a 30-day rolling average basis. These final amendments establish limits of 40 parts per million by volume (ppmv) NO_X (or 0.04 pounds per million British thermal units (lb/MMBtu) and 60 ppmv NO_X (or 0.06 lb/MMBtu) for natural draft and forced draft process heaters, respectively. Co-fired process heaters, designed to operate on gaseous and liquid fuel (*e.g.,* oil), must meet either 150 ppmv NO_X or alternative heating value-based limits, weighted based on oil and gas use. The NSPS also contains an alternative compliance option that allows owners and operators to obtain EPA approval for a site-specific NO_X limit for process heaters that may have difficulty meeting the standards under certain situations. These final amendments also include monitoring, recordkeeping and reporting requirements necessary to demonstrate compliance with the NO_X emission standards.

For flares, these final amendments define a flare as a separate affected facility rather than a type of fuel gas combustion device. As such, these final amendments remove requirements for flares to comply with the performance standards for sulfur dioxide (SO_2) (expressed as a 162 ppmv short-term hydrogen sulfide (H_2S) concentration limit) and, instead, establish a separate suite of standards for flares. We are not finalizing the requirement in the December 22, 2008, proposed amendments for flares to meet the long-term 60 ppmv H_2S fuel gas concentration limit. As explained in section IV of this preamble, we determined that requiring refineries to ensure the fuel gas they send to their flares meets a long-term H_2S concentration of 60 ppmv is not appropriate for flares.

Affected flares are those that were modified, reconstructed or constructed after June 24, 2008. In general, a flare is modified if a connection is made into the flare header that can increase emissions from the flare. The NSPS specifically identifies certain connections to a flare that do not constitute a modification of the flare because they do not result in emissions increases.

The final amendments for flares include a suite of standards that apply at all times. This suite of standards requires refineries to: (1) Develop and implement a flare management plan; (2) conduct root cause analyses and take corrective action when waste gas sent to the flare exceeds a flow rate of 500,000 standard cubic feet per day (scfd) above the baseline flow or contains sulfur that, upon combustion, will emit more than 500 pounds (lb) of SO_2 in a 24-hour period; and (3) optimize management of the fuel gas by limiting the short-term concentration of H_2S to 162 ppmv during normal operating conditions.

The final amendments require that flares be equipped with flow and sulfur monitors except in cases where flares are used infrequently or are configured such that they cannot receive high sulfur gas. For flares that are configured such that they only receive inherently low sulfur gas streams, continuous sulfur monitors are not necessary because a root cause analysis will be triggered by an exceedance of the flow rate threshold long before they exceed the 500 lb SO_2 trigger in a 24-hour period.

For infrequently used flares, the NSPS allows for less burdensome monitoring, consisting of monitoring the differential pressure between the flare header and the flare water seal to determine if a gas release to the flare has occurred. Any instance where the pressure upstream of the water seal (expressed in inches of water) exceeds the water seal height triggers a requirement to perform a root cause analysis and corrective action analysis, unless the discharge is related to flare gas recovery system compressor cycling or a planned startup or shutdown (of a refinery process unit or ancillary equipment connected to the flare) following the procedures in the flare management plan. The NSPS also contains an alternative compliance option for refinery flares located in the South Coast Air Quality Management District (SCAQMD) or the Bay Area Air Quality Management District (BAAQMD). An affected flare subject to 40 CFR part 60, subpart Ja may elect to comply with SCAQMD Rule 1118 or both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of subpart Ja.

3. Costs and Benefits

The provisions for flares and other fuel gas combustion devices (*i.e.,* process heaters and boilers) from the final June 2008 standards were stayed. The analysis for this final rule includes the same unit costs for the flare provisions as the final June 2008 rule but reflects recalculated total costs using data collected in the March 2011 information collection request (ICR) to update the number of flares. For the June 2008 standards, we estimated that 40 flares would be affected. We now anticipate that there will be 400 affected flares *that will be subject to this final rule.* Table 2 includes the recalculated cost estimates based on the updated number of flares since 2008, broken out by specific flare requirements. For the other fuel gas combustion devices, the total annualized costs for those provisions were estimated at $24 million (2006 dollars) in the June 2008 rule and remain the same. As discussed below, because there are no additional incremental costs associated with the other fuel gas combustion device provisions, we consider those annual costs accounted for in the final June 2008 standards. We are presenting these costs and benefits here again, even though we estimate no changes to them, since these provisions will become effective upon this final action to lift the stay on certain provisions in the June 2008 rule. For the June 2008 rule, we estimated the benefits to be $220 million to $1.9 billion and $200 to $1.7 billion at a 3-percent discount rate and 7-percent discount rate, respectively.[1]

Cost impacts for flares are presented in Table 2. The estimated total capital cost of complying with the final amendments to 40 CFR part 60, subpart Ja for flares is $460 million dollars (2006 dollars). The estimated annual cost, including annualized capital costs, is a cost savings of about $79 million (2006 dollars) due to the replacement of some natural gas purchases with recovered flare gas and the retention of intermediate and product streams due to a reduction in the number of malfunctions associated with refinery process units and ancillary equipment connected to the flare. Note that not all refiners will realize a cost savings since we only estimate that refineries with high flare flows will install vapor recovery systems. Although the rule does not specifically require installation of flare gas recovery systems, we project that owners and operators of flares receiving high waste gas flows will conclude, upon installation of monitors, implementation of their flare management plans, and implementation of root causes analyses, that installing flare gas recovery would result in fuel savings by using the recovered flare gas where purchased natural gas is now being used to fire equipment such as boilers and process heaters. The flare management plan requires refiners to conduct a thorough review of the flare system so that flare gas recovery systems are installed and used where these systems are warranted. As part of the development of the flare management plan, refinery owners and operators must provide rationale and supporting evidence regarding the flare waste gas reduction options considered. In addition, consistent with Executive Order 13563 (Improving Regulation and Regulatory Review, issued on January 18, 2011), for facilities implementing flare gas recovery, we are finalizing provisions that would allow the owner or operator to reduce monitoring costs and the number of root cause analyses, corrective actions, and corresponding recordkeeping and reporting they would need to perform. The costs calculated for this rule, however, do not account for potential savings due to these provisions (reduced monitoring, root cause analysis, etc.). We estimate that the final requirements for flares will reduce emissions of SO$_2$ by 3,200 tons per year (tons/yr), NO$_X$ by 1,100 tons/yr and volatile organic compounds (VOC) by 3,400 tons/yr from the baseline. The overall cost effectiveness is a cost savings of about $10,000 per ton of combined pollutants removed. We also estimate that the final requirements for flares will result in emissions reduction co-benefits of CO$_2$ equivalents by 1,900,000 metric tonnes per year, predominantly as a result of our estimate of the largest flares employing flare gas recovery, and to a lesser extent, as a result of the flow rate root cause analyses and corrective actions applicable to all flares.

TABLE 2—COST IMPACTS FOR PETROLEUM REFINERY FLARES SUBJECT TO AMENDED STANDARDS UNDER 40 CFR PART 60, SUBPART JA

[Fifth year after the effective date of these final rule amendments]

Subpart Ja requirements	Total capital cost ($1,000)	Total annual cost without credit ($1,000/yr)	Natural gas offset/product recovery credit ($1,000)	Total annual cost ($1,000/yr)	Annual emission reductions (tons SO$_2$/yr)	Annual emission reductions (tons NO$_X$/yr)	Annual emission reductions (tons VOC/yr)	Cost effectiveness ($/ton emissions reduced)
Majority of flares (approximately 360 flares)								
Flare Monitoring	72,000	12,000	0	12,000	0	0	0	
Flare gas recovery	0	0	0	0	0	0	0	
Flare Management	0	790	0	790	0	0	270	2,900
SO$_2$ RCA/CA	0	1,900	0	1,900	2,600	0	0	760
Flowrate RCA/CA		900	(6,700)	(5,800)	3.4	50	390	(13,000)
Subtotal[1]	72,000	16,000	(6,700)	9,000	2,600	50	660	2,700
Largest flares (approximately 40 flares)[2]								
Flare Monitoring	12,000	2,000	0	2,000	0	0	0	
Flare gas recovery	380,000	78,000	(170,000)	(90,000)	380	1,100	2,700	(22,000)
Flare Management	0	88	0	88	0	0	30	2,900
SO$_2$ RCA/CA	0	220	0	220	290	0	0	760
Flowrate RCA/CA	0	100	(740)	(640)	0.4	6	43	(13,000)
Subtotal[1]	390,000	81,000	(170,000)	(88,000)	660	1,100	2,800	(20,000)
Total[1]	460,000	96,000	(180,000)	(79,000)	3,200	1,100	3,400	(10,000)

[1] All estimates are rounded to two significant figures so numbers may not sum down columns.

[2] The EPA has conducted an alternative analysis that presents the costs and benefits of the rule assuming that no refiners will opt to install flare gas recovery systems as part of their flare management strategy. This analysis is presented in the Regulatory Impact Analysis in the discussion provided in the executive summary and in Section 4.1, available in the docket for this rulemaking.

We estimate the monetized benefits of this final regulatory action for all flares to be $260 million to $580 million (3-percent discount rate) and $240 million to $520 million (7-percent discount rate for health benefits and 3-percent discount rate for climate benefits). For small flares only, we estimate the monetized benefits are $170 million to $410 million (3-percent discount rate) and $150 million to $370 million (7-percent discount rate for health benefits

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[1] It is important to note that the EPA has implemented several substantial changes to the benefits methodology since 2008, which makes it challenging to compare the benefits of the June 2008 rule to the benefits of the current rulemaking. The changes with the largest impact on the range of monetized benefits are the removal of the assumption of a threshold in the concentration-response function, the revision of the value-of-a-statistical-life, and the range of risk estimates from epidemiology studies rather than the range of risk estimates supplied by experts. See the regulatory impact analysis for the current rulemaking for more information regarding these changes, which is available in the docket.

and 3-percent discount rate for climate benefits). For large flares only, we estimate the monetized benefits are $93 million to $160 million (3-percent discount rate) and $88 million to $150 million (7-percent discount rate for health benefits and 3-percent discount rate for climate benefits). Several benefits categories, including direct exposure to SO_2 and NO_X benefits, ozone benefits, ecosystem benefits and visibility benefits are not included in these monetized benefits. All estimates are in 2006 dollars for the year 2017.

Although this final rule provides refiners with some additional compliance options and removes some requirements, such as the long-term H_2S limit for flares, the cost savings due this increased flexibility have not been calculated for inclusion in the benefit-cost analysis.

B. Background of the Refinery NSPS

Section 111(b)(1)(A) of the Clean Air Act (CAA) requires the EPA to establish federal standards of performance for new, modified and reconstructed sources for source categories which cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The standard of performance must reflect the application of the best system of emission reductions (BSER) that (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 (CAA section 111(a)(1)). If it is not feasible to prescribe or enforce a standard of performance, the Administrator may instead promulgate a design, equipment, work practice or operational standard, or a combination of these types of standards (CAA section 111(h)(1)). Since 1970, the NSPS have been successful in achieving long-term emissions reductions in numerous industries by assuring cost-effective controls are installed on newly constructed, reconstructed or modified sources.

The level of control prescribed by CAA section 111 historically has been referred to as ''Best Demonstrated Technology'' or BDT. In order to better reflect that CAA section 111 was amended in 1990 to clarify that ''best systems'' may or may not be ''technology,'' the EPA is now using the term ''best system of emission reduction'' or BSER in its rulemaking packages. See, *e.g.,* 76 FR 52738, 52740 (August 23, 2011); 76 FR 63878, 63879 (October 14, 2011). As was done previously in analyzing BDT, the EPA uses available information and considers the emissions reductions achieved by the different systems available and the costs of achieving those reductions. The EPA also considers the ''other factors'' prescribed by the statute in its BSER analysis. After considering all of this information, the EPA then establishes the appropriate standard representative of BSER. Sources may use whatever system meets the standard.

Section 111(b)(1)(B) of the CAA requires the EPA to periodically review and, as appropriate, revise the standards of performance to reflect improvements in methods for reducing emissions. As a result of our periodic review of the NSPS for petroleum refineries (40 CFR part 60, subpart J), we proposed amendments to the current standards of performance and separate standards of performance for new process units (40 CFR part 60, subpart Ja) (72 FR 27278, May 14, 2007) and we subsequently promulgated those amendments and new standards (73 FR 35838, June 24, 2008). Following promulgation, we received three separate petitions for reconsideration from: (1) The American Petroleum Institute (API), the National Petrochemical and Refiners Association (NPRA) and the Western States Petroleum Association (WSPA) (collectively referred to as ''Industry Petitioners''); (2) HOVENSA, LLC (''HOVENSA''); and (3) the Environmental Integrity Project, Sierra Club and Natural Resources Defense Council (collectively referred to as ''Environmental Petitioners''). On September 26, 2008, the EPA issued a **Federal Register** notice (73 FR 55751) granting reconsideration of the following issues: (1) The newly promulgated flare modification provision[2]; (2) the ''flare'' definition; (3) the fuel gas combustion device sulfur limits as they apply to flares; (4) the flow limit for flares; (5) the total reduced sulfur and flow monitoring requirements for flares; and (6) the NO_X limit for process heaters. The EPA also granted Industry Petitioners' and HOVENSA's request for a 90-day stay for those same provisions under reconsideration. On December 22, 2008, three **Federal Register** notices (73 FR 78260, 73 FR 78546 and 73 FR 78549) were published to extend this stay until a final decision is reached on those issues.

In the September 26, 2008, **Federal Register** notice (73 FR 55751), we also identified other issues for which Petitioners requested reconsideration. We stated that, at that time, we were ''taking no action on all of the other issues raised in the petitions but will consider all of the outstanding issues in a future notice.'' On December 29, 2009, we sent a letter to the Petitioners, through their counsel, stating that ''[t]he Administrator has decided to grant reconsideration of all the remaining issues'' and that ''EPA will address the substantive aspects of the issues under reconsideration through notice and comment actions published in the **Federal Register**.'' A copy of the letter to the Petitioners can be found in the docket for this rulemaking (Docket Item No. EPA–HQ–OAR–2007–0011–0318).

In this action, we are finalizing the amendments for which we granted reconsideration and a stay as outlined in the September 26, 2008, notice and for which we proposed amendments on December 22, 2008. We are also addressing certain other minor issues raised by Industry Petitioners in this action, as discussed later in this preamble. We will take action on all of the remaining issues raised by Petitioners for reconsideration in future notices.

We received a total of 22 comments from the following groups on the proposed amendments during the public comment period: (1) Refineries, industry trade associations and consultants; (2) state and local environmental and public health agencies; (3) environmental groups; and (4) other members of the public. These final amendments reflect our full consideration of all of the comments we received. Detailed responses to the comments not included in this preamble, as well as more detailed summaries of the comments addressed in this preamble, are contained in *Standards of Performance for Petroleum Refineries: Background Information for Final Amendments—Summary of Public Comments and Responses,* dated December 2011, which is included in Docket ID No. EPA–HQ–OAR–2007–0011.

In summary, major comments on the proposed process heater requirements were related to the proposed NO_X concentration limits, the alternative heating value limits, consideration of turndown (*i.e.,* when a process heater is operated at less than 50-percent design capacity) and other factors that influence the achievable emissions

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[2] The September 26, 2008, **Federal Register** notice (73 FR 55751) described the first issue for which the EPA granted reconsideration as ''the definition of 'modification.''' However, because what we are actually reconsidering is the specific flare modification provision that applies to flares at petroleum refineries rather than the more generally applicable definition of ''modification,'' we have revised the description of this issue as ''the newly promulgated flare modification provision.''

limits. In response, we are raising the limit for new forced draft process heaters from 40 ppmv NO_X at proposal to 60 ppmv NO_X. For both natural draft and forced draft process heaters, we are finalizing alternative heating value limits derived from a more direct numerical conversion of the NO_X concentration limit (*i.e.,* 0.04 lb/MMBtu for natural draft and 0.06 lb/MMBtu for forced draft). For newly constructed, modified and reconstructed natural draft and forced draft process heaters, we are reducing the averaging time for compliance from a 365-day rolling average to a 30-day rolling average applicable during periods of normal operation. We are also finalizing an alternative case-specific compliance option that allows owners and operators to obtain EPA approval for a site-specific NO_X limit in certain conditions such as turndown.

Major comments on the proposed requirements for flares were related to the definition of flare modification for purposes of triggering applicability to this rule, the proposed removal of the flare flow limit, clarification of flare monitoring requirements and clarification of the differences between the requirement for flares and the requirements for other fuel gas combustion devices. We address these comments by clarifying the definition of flare modification and by expanding the list included in the December 22, 2008, proposal, which specifies certain connections that do not constitute a modification of the flare because they do not result in emissions increases. We are finalizing the proposed removal of the flare flow limit and instead, we are promulgating a suite of work practice standards that apply to affected flares. Based on comments received on the December 22, 2008 proposal, we are finalizing definitions of ''fuel gas combustion device'' and ''flare'' to specify that a flare is a separate affected facility rather than a type of fuel gas combustion device. We are also finalizing amendments to clarify certain monitoring requirements and to provide additional monitoring alternatives under certain circumstances.

III. Summary of the Final Rules and Changes Since Proposal

NSPS for petroleum refineries (40 CFR part 60, subpart J) apply to the affected facilities at the refinery, such as fuel gas combustion devices (which include process heaters, boilers and flares), that commence construction, reconstruction or modification after June 11, 1973, but on or before May 14, 2007 (on or before June 24, 2008 for flares). The NSPS were originally promulgated on March 8, 1974, and have been amended several times. In this action, we are promulgating technical clarifications and corrections to subpart J.

New standards of performance for petroleum refineries (40 CFR part 60, subpart Ja) apply to flares that commence construction, reconstruction or modification after June 24, 2008, and other affected facilities at petroleum refineries, including process heaters and other fuel gas combustion devices that commence construction, reconstruction or modification after May 14, 2007. In this action, we are finalizing amendments to subpart Ja to address the issues raised by Petitioners regarding flares and process heaters. We are also finalizing technical corrections to subpart Ja for certain issues that were identified by Industry Petitioners in their August 21, 2008, supplement to their original administrative reconsideration request (Docket Item No. EPA–HQ–OAR–2007–0011–0246).

The following sections summarize the amendments in both 40 CFR part 60, subpart J and 40 CFR part 60, subpart Ja. Section IV contains the rationale for these amendments, while the amendments themselves follow the preamble.

A. What are the final amendments to the standards of performance for petroleum refineries (40 CFR part 60, subpart J)?

The final amendments add a new paragraph to 40 CFR 60.100 to allow 40 CFR part 60, subpart J affected sources the option of complying with subpart J by following the requirements in 40 CFR part 60, subpart Ja. The subpart Ja requirements are at least as stringent as those in subpart J, so providing this option will allow all process units in a refinery to follow the same requirements and simplify compliance. We are also removing the reference to 40 CFR 60.101a from the description of the applicability dates in 40 CFR 60.100(b) so as not to cause confusion over the definition of ''flare'' in subpart J. We are finalizing a correction to the value and units (in the metric system) for the allowable incremental rate of particulate matter (PM) emissions in 40 CFR 60.106(c)(1). We amended the units for this constant in 40 CFR 60.102(b) on June 24, 2008, and we are now correcting 40 CFR 60.106(c)(1) accordingly. Finally, we are finalizing a definition of ''fuel gas'' that incorporates the same clarifications regarding vapors from wastewater treatment units and marine tank vessel loading operations identified in the subpart Ja definition of ''fuel gas'' (described later in this preamble).

B. What are the final amendments to the standards of performance for process heaters (40 CFR part 60, subpart Ja)?

We proposed several amendments to the standards of performance for process heaters, including adding emission limits in units of lb/MMBtu, extending the emission limit averaging time from 24 hours to 365 days, raising the emission limit for modified and reconstructed forced draft process heaters and raising the emission limit for co-fired process heaters. After consideration of all of the public comments and our own additional analyses, we are finalizing the process heater requirements, as described in this section.

Table 3 presents a comparison of the proposed and final 40 CFR part 60, subpart Ja amendments for process heaters. The final amendments include four subcategories of process heaters: (1) Natural draft process heaters; (2) forced draft process heaters; (3) co-fired natural draft process heaters; and (4) co-fired forced draft process heaters. At proposal, all co-fired process heaters were included in one subcategory, for a total of three process heater subcategories, but, based on emissions data from co-fired process heaters, we divided natural draft and forced draft co-fired process heaters into separate subcategories with different emissions limits.

For each of the first two subcategories, the final amendments include a concentration-based NO_X emissions limit and a heating value-based NO_X emissions limit, both determined daily on a 30-day rolling average basis. For the natural draft process heater subcategory, the concentration-based NO_X emissions limit for newly constructed, modified and reconstructed natural draft process heaters is 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis. The heating value-based NO_X emissions limit for newly constructed, modified and reconstructed natural draft process heaters is 0.040 lb/MMBtu higher heating value basis determined daily on a 30-day rolling average basis. The averaging time for both of these limits is shorter than the 365-day averaging time that was proposed, and the heating value-based NO_X emissions limit differs from the proposed limit in that it is a more direct numerical conversion from 40 ppmv NO_X. At proposal, we provided a longer averaging time so that short periods of turndown (*i.e.,* when a process heater is operating at less than 50-percent design capacity) would not significantly affect the overall performance of the unit. Our analysis of the additional data that we obtained following the proposal supported revising all NO_X emissions limits to be on a 30-day rolling average basis, which is achievable for process heaters during periods of normal operation. These data indicate that process heaters equipped with ultra low NO_X burners meet the emission limits described above if compliance is determined on a 30-day rolling average basis. We are finalizing alternative compliance options that allow the owners and operator to establish site-specific limits applicable during certain conditions such as turndown. Section IV.A of this preamble provides additional information regarding the rationale and analyses leading to these final amendments.

For the second subcategory, forced draft process heaters, the concentration-based NO_X emissions limit for newly constructed, modified and reconstructed forced draft process heaters is 60 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis. The heating value-based NO_X emissions limit for newly constructed, modified and reconstructed forced draft process heaters is 0.060 lb/MMBtu higher heating value basis determined daily on a 30-day rolling average basis. The higher limit for new forced draft process heaters (at proposal, the limit was 40 ppmv) is based on additional data and a re-evaluation of BSER, as described later in this preamble. As with natural draft process heaters, the averaging time for both of these limits is shorter than proposed, and the final heating value-based NO_X emissions limit is a more direct numerical conversion from 60 ppmv NO_X. Section IV.A of this preamble provides additional information regarding the rationale and analyses leading to these final amendments.

For each of these subcategories, a process heater need only meet either the concentration-based NO_X emissions limit or the heating value-based NO_X emissions limit. The refinery owner or operator may choose to comply with either limit at any time, provided that they are monitoring the appropriate variables to assess the heating value-based NO_X emissions limit. If the refinery owner or operator does not choose to monitor fuel composition, then they must comply with the concentration-based NO_X emissions limit.

TABLE 3—PROPOSED AND FINAL AMENDMENTS FOR PROCESS HEATERS

	Proposal (December 22, 2008)	Final
Averaging time	365-day rolling average	30-day rolling average.
Natural Draft NO_X Emission Limits	40 ppmv or 0.035 lb/MM BTU	40 ppmv or 0.04 lb/MM BTU.
Forced Draft NO_X Emission Limits	*New:* 40 ppmv or 0.035 lb/MM BTU *M/R:* 60 ppmv or 0.055 lb/MM BTU	60 ppmv or 0.06 lb/MM BTU.
Co-fired Burner (oil and gas) NO_X Emission Limits.	150 ppmv or Weighted average based on oil at 0.27 lb/MM BTU and gas at 0.08 lb/MM BTU.	150 ppmv or Weighted average based on oil at 0.40 lb/MM BTU and gas at 0.11 lb/MM BTU forced draft and weighted average based on oil at 0.35 lb/MM BTU and gas at 0.06 lb/MM BTU for natural draft.

As proposed, initial compliance with the heating value-based emissions limits will be demonstrated by conducting a performance evaluation of the continuous emission monitoring system (CEMS) in accordance with Performance Specification 2 in appendix B to 40 CFR part 60, with EPA Method 7 of 40 CFR part 60, appendix A–4 as the Reference Method, along with fuel flow measurements and fuel gas compositional analysis. The NO_X emission rate is calculated using the oxygen (O_2)-based F factor, dry basis according to EPA Method 19 of 40 CFR part 60, appendix A–7. Ongoing compliance with this NO_X emissions limit is determined using a NO_X CEMS and at least daily sampling of fuel gas heat content or composition to calculate a daily average heating value-based emissions rate, which is subsequently used to determine the 30-day average.

The third and fourth subcategories of process heaters are co-fired process heaters. A co-fired process heater is a process heater that employs burners that are designed to be supplied by both gaseous and liquid fuels. As described in more detail in section IV.A of this preamble, co-fired process heaters do not include gas-fired process heaters that have emergency oil back-up burners. There are two compliance options for each subcategory of co-fired process heaters: (1) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; and (2) a source-specific daily average emissions limit. Unlike gas-fired process heaters, the owner or operator of a co-fired process heater must choose one emissions limit and show compliance with that limit. For co-fired natural draft process heaters, the daily average emissions limit is based on a limit of 0.06 lb/MMBtu for the gas portion of the firing and 0.35 lb/MMBtu for the oil portion of the firing. For co-fired forced draft process heaters, the daily average emissions limit is based on a limit of 0.11 lb/MMBtu for the gas portion of the firing and 0.40 lb/MMBtu for the oil portion of the firing. These limits are different than proposed, based on a re-evaluation of BSER with new data received during the public comment period. All of the requirements for emissions monitoring, recordkeeping and reporting for co-fired process heaters are the same as for the other process heater subcategories.

We are also finalizing an alternative compliance option that allows owners and operators to obtain EPA approval for a site-specific NO_X limit for certain process heaters. This compliance option was provided in the proposed amendments, but it was limited to (1) natural draft and forced draft modified or reconstructed process heaters that lack sufficient space to accommodate combustion modification-based technology and (2) natural draft and forced draft co-fired process heaters. In the final amendments, we are finalizing this compliance option for those process heaters mentioned above while also providing this compliance option for the following additional types of process heaters: (3) modified or reconstructed induced draft process heaters that have downwardly firing burners and (4) forced draft and natural draft process heaters that operate at low firing rates, or turndown, for an extended period of time. As we noted in the preamble to the proposed amendments, in limited cases, existing natural draft or forced draft process heaters have limited firebox size or other constraints such that they cannot apply the BSER of ultra-low NO_X burners or otherwise meet the applicable limit and some co-fired units may not be able to achieve the NO_X limitations even with ultra-low NO_X burner control technology. In addition, commenters noted that downwardly fired process heaters with induced draft fans have similar NO_X control issues as forced draft heaters, but the definition of forced draft heater does not include these induced draft heaters (these are defined as natural draft process heaters). Therefore, we added a provision to allow induced draft process heaters with downwardly-firing burners to use the alternative compliance option.

Finally, we note that the emissions limits for forced draft and natural draft gas-fired process heaters are based on the performance of ultra-low NO_X burner control technologies. The ultra-low NO_X burner technology suppliers recommend operating with higher excess air rates at low firing rates (at or below approximately one-half of the maximum firing capacity), which causes higher NO_X concentrations at low firing rates. Therefore, all types of process heaters with ultra-low NO_X burner control technologies may be unable to meet the emissions limits if they are operated at low firing rates for an extended period of time. Requesting a site-specific emissions limit requires a detailed demonstration that the application of the ultra-low NO_X burner technology is not feasible or that the technology cannot meet the NO_X emissions limits given the conditions of the process heater (downward fired induced draft, co-fired or prolonged turndown); the refinery must also conduct source tests in developing a site-specific emissions limit for its process heater. This analysis must be submitted to and approved by the Administrator.

We are finalizing the proposed clarification that owners and operators of process heaters in any subcategory with a rated heating capacity of less than 100 million British thermal units per hour (MMBtu/hr) have the option of using CEMS. The final rule states that owners and operators of process heaters subject to 40 CFR part 60, subpart Ja should use CEMS to demonstrate compliance unless the heater is equipped with combustion modification-based technology (low-NO_X burners or ultra-low NO_X burners) with a rated heating capacity of less than 100 MMBtu/hr; owners and operators of those specific process heaters have the alternative option of biennial source testing to determine compliance. As requested by commenters, we have provided additional detail in the final rule regarding how to develop the O_2 operating limit, including provisions on how to develop an O_2 operating curve to ensure compliance with the NO_X emission limit at different process heater firing rates. We are requiring that owners and operators with process heaters in any subcategory that are complying using biennial source testing establish a maximum excess O_2 concentration operating limit or operating curve that can be met at all times, even during turndown, and comply with the O_2 monitoring requirements for ongoing compliance demonstration.

C. What are the final amendments to the standards of performance for flares (40 CFR part 60, subpart Ja)?

We proposed several amendments to the standards of performance for flares, including, but not limited to, amending the flare modification provision, removing the numerical limit on the flow rate to the flare, revising the flare management plan requirements to include a list of connections to the flare and an identification of baseline conditions, clarifying when a root cause analysis is required, revising the sulfur and flow monitoring requirements and providing additional time for compliance. After consideration of all of the public comments, and our own additional analyses, we are finalizing the flare requirements, as described in this section.

We did not propose to revise the definitions of ''fuel gas combustion device'' and ''flare'' on December 22, 2008. However, based on public comment and changes to the flare requirements, as described later in this section, we have decided to finalize revisions to these definitions to specify that, for purposes of 40 CFR part 60, subpart Ja, a flare is a separate affected facility rather than a type of fuel gas combustion device. This change makes clearer the differences between the requirements for flares and the requirements for fuel gas combustion devices, particularly in terms of sulfur and flow rate monitoring requirements and thresholds for root cause analyses and corrective action analyses. We are also making corrections, as needed, in numerous paragraphs throughout subpart Ja for consistency with the amended definitions (*e.g.,* adding ''and flares,'' where applicable, to paragraphs with requirements for ''fuel gas combustion devices'').

We are finalizing the flare modification provision in 40 CFR 60.100a(c), as described below, to specify certain connections to a flare that do not constitute a modification of the flare because they do not result in emissions increases. On December 22, 2008, we proposed that the following types of connections to a flare would not be considered a modification of the flare: (1) Connections made to install monitoring systems to the flares; (2) connections made to install a flare gas recovery system; (3) connections made to replace or upgrade existing pressure relief or safety valves, provided the new pressure relief or safety valve has a set point opening pressure no lower and an internal diameter no greater than the existing equipment being replaced or upgraded; and (4) replacing piping or moving an existing connection from a refinery process unit to a new location in the same flare, provided the new pipe diameter is less than or equal to the diameter of the pipe/connection being replaced/moved. We are finalizing those proposed amendments and also adding the following types of connections to the list of connections to flares that are not modifications of flares: (1) Connections between flares; (2) connections for flare gas sulfur removal; and (3) connections made to install redundant flare equipment (such as a back-up compressor). We are also clarifying one of the proposed exemptions to indicate that connections made to upgrade or enhance components of flare gas recovery systems (*e.g.,* additional compressors or recycle lines) are not modifications.

We are not finalizing the proposed amendment to provide additional time for flares that need to install additional amine scrubbing and amine stripping columns to meet the requirement to limit the long-term concentration of H_2S to 60 ppmv (determined daily on a 365 successive calendar day rolling average basis) (hereafter referred to as the long-term 60 ppmv H_2S fuel gas concentration limit). Instead, based on comments received during the public comment period for the proposed amendments and our own additional analyses, we are removing the requirement for flares to meet the long-term 60 ppmv H_2S fuel gas concentration limit. As explained in section IV, we determined that requiring refineries to ensure the fuel gas they send to their flares meets a long-term H_2S concentration of 60 ppmv is not appropriate for flares.

We are promulgating final amendments for flares that include a suite of standards that apply at all times that are aimed at reducing SO_2 emissions from flares. These amendments include several provisions that were proposed on December 22, 2008, as well as others that differ from those proposed, but are a logical outgrowth of the proposed amendments. This suite of standards requires refineries to: (1) Develop and implement a flare management plan; (2) conduct root cause analyses and take corrective action when waste gas sent to the flare exceeds a flow rate of 500,000 standard cubic feet (scf) above the baseline flow to a flare in any 24-hour period (rather than the proposed threshold of 500,000 scf in any 24-hour period without considering the baseline); (3) conduct root cause analyses and take corrective action when the emissions from the flare exceed 500 lb of SO_2 in a 24-hour period (instead of 500 lb SO_2 above the emissions limit); and (4) optimize management of the fuel gas by limiting the short-term concentration of H_2S to 162 ppmv during normal operating conditions (determined hourly on a 3-hour rolling average basis). As explained further in preamble section IV.B, 40 CFR part 60, subpart J sets a performance standard for SO_2 (expressed as a 162 ppmv short-term H_2S concentration limit) in fuel gas entering fuel gas combustion devices. However, for this final rule, we have determined that flares should be treated separately from other fuel gas combustion devices because they meet the criteria set forth in CAA section 111(h)(2)(A) since emissions from a flare do not occur ''through a conveyance designed and constructed to emit or capture such pollutant.'' The flare itself is not a ''conveyance'' that is ''emitting'' or ''capturing'' these pollutants. Instead, pollutants such as SO_2 are created in the flame that burns outside the flare tip. Therefore, we have determined that this suite of work practice standards, which includes optimization of fuel gas management (based on limiting concentration of H_2S to 160 ppmv) is more appropriate for flares, as opposed to the H_2S performance standard in subpart J, applicable to fuel gas systems. See section IV.B of this preamble for a more detailed explanation of these requirements. In this rule, we are using the term ''normal operating conditions'' to describe situations where the process is operating in a routine, predictable manner, such that the gases from the process are predictable, as opposed to less-predictable swings related to emergency situations during which the flare begins to operate as a safety device. All of these requirements will apply during the vast majority of the time. Under a very narrow and limited set of circumstances, such as when a flare is used as a safety device under emergency conditions,[3] the flare will be subject to all of these requirements except for the requirement to optimize management of the fuel gas.

In addition, we are specifying that, if a discharge exceeding either or both of the SO_2 or flow thresholds described above is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the flare, and the flare management plan procedures for minimizing flow (which minimizes emissions) during that type of event are followed, a root cause analysis and corrective action analysis are not required. Finally, we are finalizing the proposed added provisions to ensure that owners and operators implement corrective actions on the findings of the SO_2 or flow rate root cause analyses and to specify a deadline for performing the corrective actions.

We are finalizing the proposed amendment to remove the 250,000 scfd 30-day average flow rate limit. Our rationale for this decision is explained in the preamble to the proposed amendments (73 FR 78530) and also in section IV of this preamble.

We are finalizing one proposed amendment to the flare management plan and adding several new requirements as a logical outgrowth of the proposed amendments, considering the public comments we received, to ensure compliance with the flare standards. First, as proposed, we are requiring a list of refinery process units and fuel gas systems connected to each affected flare. However, we are also adding a requirement for a simple process flow diagram showing the design of the flare, connections to the flare header and subheader system(s), and all gas lines associated with the flare. With these two requirements, we are clarifying that the flare management plan must include a diagram of the flare and connections, but the diagram need not be a detailed piping and instrumentation diagram that shows all process units and ancillary equipment connected to the flare. We are also requiring the owner and operator of an affected flare to assess and minimize flow to affected flares from these process units and fuel gas systems. Second, we are adding new requirements that the flare management plan include design and operation details about the affected flare, including tip diameter, type of flare, monitoring methods and a description of the flare gas recovery system, if present. The inclusion of these details will ensure that the rest of the flare management plan is reasonable and appropriate for that affected flare.

Third, as a logical outgrowth of the proposed amendments, considering the public comments we received, we are adding a new requirement for owners and operators to determine the baseline flow to each flare, including purge and sweep gas, and include this baseline flow in the flare management plan. As described later in this preamble, developing the baseline is important because the final threshold for the flare flow root cause analysis takes this baseline flow into consideration. Finally, we are adding a new requirement to minimize the volume of gas flared during maintenance of a flare gas recovery system.

We have decided to remove the requirement for the owner or operator to explain in the flare management plan how a root cause analysis and corrective action analysis will be conducted if the flow to the flare exceeds the specified threshold. Instead, all the requirements for determining when and how to conduct a root cause analysis and corrective action analysis, and the requirements for when and how to implement a corrective action, have been expanded, as described later in this section, and moved to 40 CFR 60.103a(c) through (e).

We are specifying that, for modified flares, the flare management plan must be developed and implemented by no later than November 11, 2015 or upon startup of the modified flare, whichever is later (the proposed amendments provided 18 months with an additional 6 months if the owner or operator committed to installing a flare gas recovery system). In addition, because of the lack of a direct flow limit and the addition of the baseline flow value, we are adding a requirement that the flare management plan must be submitted to the Administrator.

As with the flare management plan, the owner or operator of an affected flare must comply with the root cause analysis and corrective action analysis requirements within 3 years from the effective date of this final rule or upon startup of the modified flare, whichever is later.

We are finalizing several proposed amendments to the sulfur monitoring requirements and revising other requirements as a logical outgrowth of the proposed amendments, considering the public comments we received. We consolidated the proposed alternatives to monitor reduced sulfur compounds and total sulfur compounds into a

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[3] *Background Information for New Source Performance Standards,* Vol. 3, Promulgated Standards (APTD–1352c; Publication No. EPA 450/2–74–003), pg 127 (February 1974) (*NSPS BID Vol. 3*).

provision that allows the use of total reduced sulfur monitoring. We also clarified the span requirements for these monitors and are allowing the use of cylinder gas audits for relative accuracy assessments. We are finalizing the H_2S monitoring alternative method for determining total sulfur content in the flare gas, as proposed, but we have clarified the span requirements for this monitor and are allowing the use of cylinder gas audits for relative accuracy assessments, similar to the total reduced sulfur monitor requirements. For refineries that measure SO_2 concentrations in the exhaust from a fuel gas combustion device that combusts gas representative of the gas discharged to the flare, we added an alternative to allow the owner or operator to use the existing SO_2 CEMS data to calculate the total sulfur content in the flare gas.

We received public comments stating that the flow and sulfur monitoring requirements for flares were too burdensome for flares that are used infrequently or that are configured such that they cannot receive high sulfur flare gas. Based on our evaluation of these comments, we are providing new alternatives to continuous flow and sulfur monitoring for certain flares. First, for flares that are configured such that they only receive inherently low sulfur gas streams described in 40 CFR 60.107a(a)(3)(i) through (iv) or (b), continuous sulfur monitors are not necessary because a root cause analysis will be triggered by an exceedance of the flow rate threshold long before they exceed the 500 lb SO_2 trigger in a 24-hour period.

Second, we are providing an alternative monitoring option for emergency flares, secondary flares and flares equipped with a flare gas recovery system designed, sized and operated to capture all flows (except flows resulting from planned startup and shutdown that are addressed in the flare management plan). If this option is applicable, the owner or operator may elect to continuously monitor the water seal height and the pressure in the flare header just upstream of the water seal rather than install total sulfur and flow monitoring systems. If this monitoring option is selected, any instance where the pressure upstream of the water seal (expressed in inches of water) exceeds the water seal height triggers a requirement to perform a root cause analysis and corrective action analysis, unless the discharge is related to flare gas recovery system compressor cycling or a planned startup or shutdown (of a refinery process unit or ancillary equipment connected to the flare) following the procedures in the flare management plan. An ‘‘emergency flare’’ is a flare that combusts gas exclusively released as a result of malfunctions (and not startup, shutdown, routine operations or any other cause) and is characterized as having four or fewer discharge events in any 365 consecutive calendar days.

Owners or operators of affected flares that have flare gas recovery systems with staged compressors that elect to use this monitoring option must identify these flares in their flare management plan, identify the time period required for the staged compressors to actively start to recover gas and identify the operating parameters monitored and procedures employed to minimize the duration of flaring during compressor staging. If a pressure exceedance is caused during compressor staging and the duration of the pressure exceedance is less than the time specified in the flare management plan, then a root cause analysis is not required and the pressure exceedance is not required to be reported. If a pressure exceedance is not attributable to compressor staging (*i.e.,* all staged compressors are active), if a pressure exceedance is the result of a planned startup and shutdown event during which the flare management plan is not followed or if the duration of a pressure exceedance attributable to compressor staging is greater than the time specified in the flare management plan, then a root cause analysis and corrective action analysis are required and the pressure exceedance must be reported. More than four pressure exceedances required to be reported, as described above and under 40 CFR 60.108a(d)(5) (hereafter referred to as ‘‘reportable pressure exceedances’’) in any 365 consecutive calendar days is an indication that the flare gas recovery system is not adequately sized, and the sulfur and flow monitors, as required in 40 CFR 60.107a(e) and (f), must be installed if that occurs.

Third, we are clarifying that monitors for flow and sulfur on the second flare in a staged flare configuration are not required where the water seal monitoring requirements adequately and appropriately address this scenario. Under most circumstances, the root cause analysis is expected to be triggered, based on the flow to or emissions from the primary flare. However, in cases where the capacity of the primary flare is small (less than 500,000 scfd), this may not always be the case. Additionally, we consider the water seal monitoring on the secondary flare to be appropriate to ensure that gases are not released to the secondary flare inadvertently. We clarify in this final rule that if a root cause analysis is triggered for the primary flare, releases to the secondary flare do not trigger an additional root cause analysis (*i.e.,* the releases may be treated as one event). However, if flow is diverted to the secondary flare, then a root cause analysis is required, even if a root cause analysis was not triggered for the primary flare, based on flow rate or SO_2 emissions. In addition, if flow is diverted to the secondary flare five or more times in a 365-day period, flow monitoring of the secondary flare is required. We anticipate that the upstream sulfur monitor on the primary flare can be used to determine the sulfur content of the gas diverted to the secondary flare.

In response to comments, we are also finalizing a new amendment providing an alternative compliance option in 40 CFR 60.103a(g) and 40 CFR 60.107a(h) for certain flares. Specifically, for refineries located in the SCAQMD, an affected flare subject to 40 CFR part 60, subpart Ja may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements for flares in 40 CFR 60.103a(a) through (e) and the associated monitoring provisions in 40 CFR 60.107a(e) and (f). Similarly, for refineries located in the BAAQMD, an affected flare subject to subpart Ja may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements for flares in 40 CFR 60.103a(a) through (e) and the associated monitoring provisions in 40 CFR 60.107a(e) and (f). We are also finalizing specific provisions within the standards for owners or operators (and manufacturers of equipment) to submit a request for a determination of equivalence for ‘‘an alternative means of emission limitation’’ that will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved under any of the final subpart Ja design, equipment, work practice or operational requirements in accordance with CAA section 111(h).

For fuel gas combustion devices and sulfur recovery plants, we are correcting and clarifying the threshold for a root cause analysis and corrective action analysis. The proposed root cause analysis threshold for both types of process units was 500 lb SO_2 above the emission limit, but the proposed amendments directed the owner or operator to compare the SO_2 emissions to ‘‘the period of the exceedance’’ for fuel gas combustion devices and ‘‘the entire 24-hour period’’ for sulfur recovery plants. That language meant that if one 12-hour average for a sulfur recovery plant was above the emission limit, the owner or operator would have compared those emissions to the emissions allowed over an entire 24 hours to determine if root cause analysis was required. However, although a 12-hour average above the emission limit clearly means that more SO_2 was emitted than allowed by that emissions limit, it is possible that, since the time periods being compared were not analogous, the ''allowed emissions'' over 24 hours could be more than the actual emissions that made up the one 12-hour average. Upon further consideration, we see no reason for the requirements to be different for fuel gas combustion devices and sulfur recovery plants. Therefore, we are finalizing an amendment that states that the threshold for a root cause analysis and corrective action analysis for both sulfur recovery plants and fuel gas combustion devices is 500 lb above the emission limit during one or more consecutive periods of excess emissions[4] or any 24-hour period, whichever is shorter. This clarifying amendment is needed to ensure that the magnitude of the emissions limit exceedance is properly compared to what would have been emitted if the emissions were equivalent to the emissions limit based on the averaging time allowed for that emissions limit.

Finally, we are finalizing the amendments at 40 CFR 60.108a(c) and (d) mostly as proposed to clarify recordkeeping and reporting when a root cause analysis and corrective action analysis are required. These clarifications were needed to more clearly delineate the differences in the recordkeeping and reporting requirements for flares, fuel gas combustion devices and sulfur recovery plants. The differences between the proposed amendments and the final amendments are corrections to be consistent with changes to the root cause analysis and corrective action analysis requirements already described. We are also finalizing 40 CFR 60.108a(c), as proposed, to add recordkeeping requirements for the proposed monitoring option that is based on periodic manual sampling and analysis to determine the total sulfur-to-H_2S ratio.

D. What are the final amendments to the definitions in 40 CFR part 60, subpart Ja?

We proposed amendments to a number of definitions in 40 CFR 60.101a. This section describes whether we are finalizing the amendments as proposed, finalizing an amendment different than (but as a logical outgrowth of) what was proposed or not finalizing the proposed amendment.

We are finalizing amendments to the definitions of ''flexicoking unit'' and ''fluid coking unit,'' as proposed.

We are finalizing a definition of ''delayed coking unit'' that is different than the proposed amendments to clarify what pieces are included in a delayed coking unit. The final June 2008 rule did not explicitly describe the pieces of a delayed coking unit. We proposed to amend the definition in December 2008 to specify that a delayed coking unit ''consists of the coke drums and associated fractionator.'' In the course of evaluating public comments on the proposed definition, we looked more closely at the operation of delayed coking units and determined that the fractionators, quench water system and coke cutting equipment are integral to the operation of a delayed coking unit. Therefore, we are revising the definition of ''delayed coking unit'' in these final amendments to include ''the coke drums associated with a single fractionator and the associated fractionator; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; process piping and associated equipment such as pumps, valves and connectors; and the coke drum blowdown recovery compressor system.'' Finally, to avoid any potential retroactive compliance issues that could arise for certain delayed coking units because of the changes to the definition of ''delayed coking unit'' between the proposal and the final rule, we are moving the date for determining applicability of NSPS subpart Ja for those newly constructed, reconstructed and modified delayed coking units specifically affected by this change from the date of the proposal to the promulgation date of these final amendments. See CAA section 111(a)(2).

We are finalizing definitions of ''forced draft process heater,'' ''natural draft process heater'' and ''co-fired process heater,'' which will enable owners and operators to determine the appropriate subcategory for each of their process heaters. Based on public comments, the final amendments have been revised slightly from the proposed definitions to clarify that induced draft systems are defined as natural draft process heaters and balanced draft systems are defined as forced draft process heaters. We are also revising the definition of ''co-fired process heater'' to clarify that this type of process heater does not include gas burners that have emergency oil back-up burners. We are finalizing the definition of ''air preheat,'' as proposed, except that we are substituting the term ''sensible'' for ''latent'' to describe the heat recovered from exhaust gases.

We are finalizing the definitions of ''flare gas recovery system'' and ''process upset gas,'' as proposed, and we are adding a new definition of ''flare gas header system.'' We are finalizing a revision to the definition of ''flare'' to refer to the ''flare gas header system'' rather than repeat the components of the flare gas header system within the definition of flare. In addition, we are clarifying in the definition of ''flare'' that, in the case of an interconnected flare gas header system (*i.e.,* two or more flare tips share the same flare gas header system or are otherwise connected such that they receive flare gas from the same source), the ''flare'' includes each combustion device serviced by the interconnected flare gas header system and the interconnected flare gas header system.

We are finalizing definitions of ''corrective action,'' ''corrective action analysis'' and ''root cause analysis'' with minor changes from proposal to update section references and to expand upon the types of factors that should be taken into consideration for root cause and corrective action analyses. We are adding definitions of ''purge gas'' and ''sweep gas'' to clarify the requirements of the flare minimization plan. We are also adding new definitions of ''emergency flare,'' ''cascaded flare system,'' ''non-emergency flare,'' ''primary flare'' and ''secondary flare'' to clarify the types of flares that are and are not allowed to use the water seal monitoring alternative for flares.

We are finalizing the amendments to the definition of ''petroleum refinery,'' as proposed. As we noted in the preamble to the proposed amendments, facilities that only produce oil shale or tar sands-derived crude oil for further processing using only solvent extraction and/or distillation to recover diluent that is then sent to a petroleum refinery are not themselves petroleum refineries. Facilities that produce oil shale or tar sands-derived crude oil and then upgrade these materials and produce refined products would be petroleum refineries. Additionally, facilities that produce oil shale or tar sands-derived

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[4] As noted above, the proposed amendments used the term ''period of the exceedance'' for fuel gas combustion devices. That term was intended to have the same meaning as a period of excess emissions (or multiple consecutive periods of excess emissions), as defined in 40 CFR 60.106a(b) or 40 CFR 60.107a(i)). Therefore, the final amendments refer to ''one or more consecutive periods of excess emissions'' rather than ''period of the exceedance.''

crude oil using any cracking process would be considered petroleum refineries.

We are not finalizing the proposed amendments to ''refinery process unit'' to avoid possible conflicts and confusion caused by having different definitions for ''refinery process unit'' in 40 CFR part 60, subparts J and Ja, but we are adding a new definition of ''ancillary equipment'' and using this term to clarify that the flare modification provisions and standards apply to the types of units listed in the proposed definition of ''refinery process unit.'' Specifically, we are defining *ancillary equipment* as equipment used in conjunction with or that serve a refinery process unit. *Ancillary equipment* includes, but is not limited to, storage tanks, product loading operations, wastewater treatment systems, steam- or electricity-producing units (including coke gasification units), pressure relief valves, pumps, sampling vents and continuous analyzer vents.

We are amending the definition of ''fuel gas,'' as proposed, to clarify that process units that gasify petroleum coke at a petroleum refinery are producing refinery fuel gases. We also proposed to amend the definition to state that gas generated by process units that calcine petroleum coke into anode grade coke is not fuel gas. Based on public comment, we are amending the definition to state that gas generated by coke calciners producing all premium grade coke (rather than just anode grade coke, as proposed) is not fuel gas. Also upon consideration of public comments, we are amending the definition of ''fuel gas'' to clarify which vapor streams we intended to exclude. The proposed definition indicated that vapors collected and combusted to comply with specific standards were not considered fuel gas. The final amended definition clarifies that vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations and asphalt processing units are not considered fuel gas, regardless of whether the action is required by another standard.

Finally, we are finalizing several proposed amendments to the definition of ''sulfur recovery plant'' to clarify the intent of the definition. We are correcting the spelling of ''H_2S.'' We are also clarifying that multiple units recovering sulfur from a common source of sour gas produced at a refinery are considered one sulfur recovery plant. In addition, we are clarifying that loading facilities downstream of the sulfur pits are not part of the sulfur recovery plant (the proposed definition only specified secondary sulfur storage vessels).

E. What are the final technical corrections to 40 CFR part 60, subpart Ja?

See Table 4 of this preamble for miscellaneous technical corrections that we are finalizing throughout 40 CFR part 60, subpart Ja. As mentioned previously, some of these technical corrections are in response to straightforward issues raised by Industry Petitioners in their August 21, 2008, supplement to their original petition for reconsideration (Docket Item No. EPA–HQ–OAR–2007–0011–0246). Other technical corrections are needed to correct typographical errors and to correct equation and paragraph designations.

TABLE 4—TECHNICAL CORRECTIONS TO 40 CFR PART 60, SUBPART JA

Section	Technical correction and reason
60.102a(f)(1)(ii)	Replace "300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (HS_2), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air" with "300 ppmv of reduced sulfur compounds and 10 ppmv of H_2S, each calculated as ppmv SO_2 (dry basis) at 0-percent excess air" for consistency of units and to correct a typographical error.
60.104a(d)(4)(ii)	Redesignate Equation 3 as Equation 5 to provide for the addition of new Equations 3 and 4.
60.104a(d)(4)(iii)	Redesignate Equation 4 as Equation 6 to provide for the addition of new Equations 3 and 4.
60.104a(d)(4)(v)	Redesignate Equation 5 as Equation 7 to provide for the addition of new Equations 3 and 4.
60.104a(d)(8)	Redesignate Equation 6 as Equation 8 to provide for the addition of new Equations 3 and 4.
60.104a(f)(3)	Redesignate Equation 7 as Equation 9 to provide for the addition of new Equations 3 and 4. Replace "hourly" with "3-hour" in the definition of the new Equation 9 variable "Opacity limit" and replace "source test runs" with "source test" in the definition of the new Equation 9 variable "$\mathrm{Opacity}_{st}$" to clarify the information required for new Equation 9.
60.104a(h)(5)(iv)	Redesignate the reference to Equation 6 as a reference to Equation 8 to provide for the addition of new Equations 3 and 4.
60.105a(b)	Replace "in § 60.102a(b)(1) shall comply with the requirements in paragraphs (b)(1) through (3) of this section" with "in § 60.102a(b)(1) that uses a control device other than fabric filter or cyclone shall comply with the requirements in paragraphs (b)(1) and (2) of this section" to clarify applicability of the requirements and remove the reference to a nonexistent paragraph.
60.105a(b)(1)	Replace "according to the requirements in paragraph (b)(1)(i) through (iii) of this section" with "according to the applicable requirements in paragraphs (b)(1)(i) through (v) of this section" to clarify and correct paragraph reference.
60.105a(b)(1)(ii)(A)	Replace "alterative" with "alternative" to correct the use of an incorrect word.
60.105a(i)(5)	Replace "Except as provided in paragraph (i)(7) of this section, all rolling 7-day periods" with "All rolling 7-day periods" to remove the reference to a nonexistent paragraph.
60.107a(a)(2)(i)	Replace "320 ppmv H_2S" with "300 ppmv H_2S" to make the span value for a H_2S monitor consistent with the span value in 40 CFR part 60, subpart J.
60.108a(d)(5)	Replace "the information described in paragraph (e)(6) of this section" with "the information described in paragraph (c)(6) of this section" to correct the reference to a nonexistent paragraph.

IV. Summary of Significant Comments and Responses

As previously noted, we received a total of 22 comments addressing the proposed amendments. These comments were received from refineries, industry trade associations, consultants, state and local environmental and public health agencies, environmental groups and members of the public. Brief summaries of the major comments and our complete responses to those comments are included in the following sections. A summary of the remainder of the comments received during the comment period and responses thereto, as well as more detailed summaries of the comments addressed in this preamble, can be found in *Standards of Performance for Petroleum Refineries: Background Information for Final Amendments—Summary of Public Comments and Responses,* which is included in the docket for the final amendments (Docket ID No. EPA–OAR–HQ–2007–0011). The docket also contains further details on all the analyses summarized in the responses below.

In responding to the public comments, we re-evaluated the cost and emission reduction impact estimates of some of the control options and re-evaluated the related BSER determinations. In our BSER determinations, we took all relevant factors into account consistent with other agency decisions.

A. Process Heaters

Comment: Commenters stated that new forced draft process heaters cannot meet the proposed emissions limit of 40 ppmv NO_X, so the EPA should revise the emissions limits for new forced draft process heaters to be the same as the limit for modified and reconstructed forced draft process heaters (60 ppmv NO_X). One commenter referenced a general technical document written by a process heater burner manufacturer regarding a new forced draft process heater at their refinery to support the assertion that new process heaters cannot meet the proposed limit without selective catalytic reduction or other add-on controls. Another commenter also requested higher emissions limits for new forced draft process heaters with air preheat.

Response: The commenters provided only limited and theoretical data to support their argument that new forced draft process heaters cannot meet the 40 ppmv (or 0.040 lb/MMBtu) NO_X emissions limit. Specifically, the John Zink white paper cited by the commenter (submitted as an attachment to Docket Item No. EPA–HQ–OAR–2007–0011–0296) stated only that the 40 ppmv emissions limit could not be ‘‘guaranteed’’ for a new forced draft process heater, based on the design conditions, which included air preheat. Actual NO_X performance data for that commenter's new forced draft process heaters are not available, as those particular process heaters are not yet operational. As such, the actual performance of these forced draft process heaters is still in question. However, we acknowledge that we only have data for one new forced draft process heater without air preheat that is currently operating that could meet a 40 ppmv NO_X emissions limit on a 365-day average. We conducted additional data evaluations to determine appropriate limits and averaging times for all process heaters at normal operating conditions while considering this and other public comments we received. As part of the data analysis effort, we obtained a year's worth of hourly CEMS data for the new forced draft process heater without air preheat capable of meeting 40 ppmv on a 365-day average. As discussed later in this section, our analysis of the additional data that we obtained following the proposal supported revising all NO_X emissions limits to be on a 30-day average basis. The data indicate that the 30-day averages for the new forced draft process heater without air preheat capable of meeting 40 ppmv on a 365-day average exceeded 40 ppmv 15 percent of the time, but none of the 30-day averages exceeded 60 ppmv NO_X.

Consequently, we are raising the NO_X emissions limit (while concurrently reducing the averaging time) for all new forced draft process heaters to be equivalent to the emissions limit for modified and reconstructed forced draft process heaters (*i.e.,* 60 ppmv or 0.060 lb/MMBtu with a 30-day averaging period). Furthermore, based on the information provided by the commenters, as well as the available performance data for existing forced draft process heaters with air preheat that have been retrofitted with ultra-low NO_X burners, we also conclude that the 60 ppmv (or 0.060 lb/MMBtu) on a 30-day rolling average basis adequately accommodates forced draft process heaters that use air preheat. Based on our review of CEMS data for new and retrofitted forced draft process heaters, we conclude that 60 ppmv (or 0.060 lb/MMBtu) on a 30-day rolling average basis is BSER for new, reconstructed or modified forced draft process heaters. (For additional details, see *Revised NO_X Impact Estimates for Process Heaters,* in Docket ID No. EPA–HQ–OAR–2007–0011.)

Comment: Commenters asserted that the heating value-based emissions limits (*i.e.,* the limits in units of lb/MMBtu) should be numerically equivalent to the concentration-based emissions limits (*e.g.,* 40 ppmv should be equivalent to 0.040 lb/MMBtu rather than 0.035 lb/MMBtu).

Response: In August 2008, Industry Petitioners provided the EPA with suggestions for revising the process heater standards (Docket Item No. EPA–HQ–OAR–2007–0011–0257). One of their recommendations was to include emissions limits based on heating value (lb/MMBtu) to account for hydrogen content variations in the fuel gas. They suggested that, on an annual basis, most natural draft process heaters could meet 0.035 lb/MMBtu and all other process heaters could meet 0.055 lb/MMBtu. We evaluated these suggested emissions limits and determined that they were reasonably equivalent to the concentration-based limits we were proposing. We also requested comment on their use and their equivalency, as described in the preamble to the proposed amendments (see 73 FR 78527). Industry commenters now assert that the emissions limit numerically equivalent to the 40 ppmv concentration limit is 0.040 lb/MMBtu and the emissions limit numerically equivalent to the 60 ppmv concentration limit is 0.060 lb/MMBtu.

We note that, as discussed in the preamble to the proposed amendments, the exact conversion from ppmv to lb/MMBtu depends on the hydrogen content of the fuel gas. However, our calculations generally support the more direct numerical conversion suggested by commenters over the typical range of hydrogen concentrations expected in the fuel gas (see *Revised NO_X Impact Estimates for Process Heaters*, in Docket ID No. EPA–HQ–OAR–2007–0011). Therefore, we are finalizing heating value-based emissions limits of 0.040 lb/MMBtu and 0.060 lb/MMBtu for natural draft process heaters and forced draft process heaters, respectively, based on direct numerical conversions from the concentration-based emissions limits.

We are also clarifying that the owner or operator must demonstrate that the process heater is in compliance with either the applicable concentration-based or heating value-based NO_X limit. The heating value-based NO_X emission rate is calculated using the oxygen (O_2)-based F factor, which is the ratio of combustion gas volume to heat input. Ongoing compliance with this NO_X emissions limit is determined using a NO_X CEMS and at least daily sampling of fuel gas heat content or composition to calculate a daily average heating value-based emissions rate, which is subsequently used to determine the 30-day average.

Specifically, if the F factor is determined at least daily, the owner or operator may elect to calculate both a 30-day rolling average NO_X concentration (ppmv, dry basis, corrected to 0-percent excess air) and a 30-day rolling average NO_X emission factor (in lb/MMBtu) and demonstrate that the process heater is in compliance with either one of these limits. For most fuel gas systems, the alternative emissions limits are expected to be identical; however, there may be instances where a process heater may be complying with one of the emissions limits and not the other. For example, a process heater combusting fuel gas with very high hydrogen content may have an average NO_X concentration above the 60 ppmv limit, but below the 0.060 lb/MMBtu limit, largely due to the concentration limit being determined on a dry basis (and understanding that the combustion of hydrogen produces only water and not carbon dioxide). Provided that the appropriate monitoring is conducted, an affected source would only be out of compliance if it exceeds both the concentration-based limit and the heating value-based limit at the same time. However, to have the option to determine compliance with the alternative heating value-based emissions limit, the refinery owner or operator must, at least daily, determine the F factor (dry basis) for the fuel gas according to the monitoring provisions in 40 CFR 60.107a(d). If the F factor is not determined at least daily, the heating value-based alternative cannot be used. Generally, fuel gas heating value is important to the overall operation of refinery boilers and process heaters; as such, refiners maintain their fuel gas within an operating range that they need to fire these sources, often by mixing with natural gas, etc., so we anticipate that most, if not all, refiners will already have this information available on a daily basis.

Comment: Several commenters addressed the need for the rule to address turndown, which is a period of time when process heaters are firing below capacity. Commenters stated that during these periods, the NO_X concentrations will likely be above the emissions limits, but the mass of NO_X emissions is no greater than when the heater is operating at full capacity because the lower firing rate results in a lower exhaust flow rate. Commenters noted that turndown conditions could exist for extended periods, so special provisions are needed for these conditions. Commenters requested a mass-based emission rate (lb/MMBtu limit multiplied by the heater's rated capacity) that would apply when the process heater is firing at less than full capacity (some commenters suggested 50 percent of capacity; one commenter suggested 70-percent capacity as a cutoff). One commenter also noted that process heaters must often operate at higher O_2 levels during turndown and requested that the proposed maximum O_2 operating limit not apply when small furnaces that are not required to install CEMS are firing at less than full capacity.

Response: In our proposed amendments, we provided a longer averaging time (365-day average) so that short periods of turn-down would not significantly affect the overall performance of the unit. However, according to the commenters, the longer averaging time does not adequately address turndown conditions. Therefore, we re-evaluated the available data, including our existing data and additional data provided by the industry, to determine the appropriate emissions limits during different types of operation, including turndown. The additional data provided by Industry and our evaluation of those data are included in the docket for the final amendments (Docket ID No. EPA–OAR–HQ–2007–0011). Based on our analysis of the data (described in greater detail in the next paragraph), we concluded that a 30-day averaging period is appropriate for the NO_X emission limits under most operating scenarios.

Upon examination of all available CEMS data, we determined that, for periods of normal operation (*i.e.,* firing at 50 percent or more of design capacity), the proposed NO_X emissions limits of 40 and 60 ppmv were not achievable for all process heaters using a 24-hour averaging period (the averaging period included in the final June 2008 rule). From the available data, short-term fluctuations in the NO_X concentrations of process heaters using ultra-low NO_X burners caused them to exceed a 24-hour average limit somewhat frequently, but a 30-day average provided adequate time to average out the short-term fluctuations. We note that a few of the process heaters operated at relatively high excess O_2 concentrations at normal conditions (*i.e.,* at exhaust O_2 concentrations of 6 percent or more). These units had periods of excess emissions above the 30-day average emission limits, but we rejected the performance of these process heaters as BSER because of the high exhaust O_2 concentrations for these units during normal (*i.e.,* non-turndown) firing rates. That is, these process heaters were not being operated optimally for reducing NO_X emissions. Furthermore, when these process heaters were operated at the lower range of exhaust concentrations for the unit (although generally higher than what would be considered optimal excess O_2 concentrations for reducing NO_X emissions), the process heater could meet the applicable 40 or 60 ppmv emissions limit on a 30-day averaging period. Based on our review of CEMS data for process heaters with ultra-low NO_X burners that operated at excess O_2 concentrations less than 6 percent (*i.e.,* operated in a manner consistent with proper low NO_X burner operation), all such process heaters could comply with the final NO_X emissions limits on a 30-day average basis. Consequently, we revised the basic emissions limits to be on a 30-day average.

As described previously in this section, we conclude that the applicable 40 or 60 ppmv emissions limit on a 30-day averaging period is achievable for process heaters during periods of normal operation. Our next step was to evaluate the achievability of the emissions limits during turndown conditions and alternative approaches for establishing emissions limitations where necessary. The following paragraphs describe our analysis of the data, including our evaluation of alternative methods for accommodating turndown conditions and our rationale for providing the site-specific alternative for extended turndown conditions.

There were very limited CEMS data available for process heaters operating under turndown conditions (*i.e.,* firing below 50 percent of design capacity). However, two general trends were observed in the CEMS data that were available: (1) Typical exhaust O_2 concentrations increase at lower firing rates; and (2) exhaust NO_X concentrations (corrected to 0-percent excess O_2) increase with increasing O_2 concentration (regardless of firing rates). These data, along with the need to operate the process heater at higher O_2 concentrations during low firing rates to maintain flame stability, suggest that an alternative NO_X emissions limit could, in some instances, be needed to address extended turndown conditions (turndown events lasting a majority of the 30-day averaging time). As such, we considered alternative compliance options to address turndown conditions.

One alternative compliance option considered to address turndown was a mass-based NO_X emissions limit that would be equivalent to the mass of NO_X emitted from a unit meeting the 0.040 (or 0.060) lb/MMBtu limit while firing at 50 percent of capacity, as suggested by commenters. However, for most units for which CEMS data are available, the alternative mass-based emissions limit did not improve the ability of the process heater to meet the emissions limit. We note that most of the process heaters were able to meet the applicable concentration-based emissions limit (40/60 ppmv) or the heating value-based (0.040/0.060 lb/MMBtu) emissions limit during turndown. Therefore, the issue appears to be limited to a few of the process heaters that must operate at relatively high excess O_2 concentrations during turndown conditions. For these units, the alternative mass-based emissions limit that we were considering rarely, if ever, provided a means for these units to comply with the performance standard.

We understand that technology providers recommend operating process heaters that are turned down at higher excess O_2 concentrations to improve flame stability and ensure safe operation of the process heater; however, based on the information provided by the technology providers, there is still an optimal excess O_2 concentration at which flame stability is achieved while minimizing NO_X formation. That is, even when a process heater is operating at less than 50-percent design capacity, excess O_2 concentrations should still be controlled to minimize NO_X formation within the safe operating constraints to maintain flame stability. We do not have specific data on process heaters that are near, but below, the concentration emissions limits when firing above 50-percent capacity, but cannot meet the concentration limit when firing below 50-percent capacity, so we have no data that show that process heaters operating at less than 50-percent design capacity and controlling excess O_2 concentrations cannot meet the emissions limits. However, we acknowledge that the correlations with firing rates and O_2 and/or NO_X concentrations and the need for higher O_2 concentrations to maintain flame stability generally support the commenter's argument that a few marginally compliant process heaters will have difficulty meeting the basic emissions limit when the unit is turned down. As such, we acknowledge that there may be periods of turndown in which a process heater is operating as recommended, but may be unable to meet the concentration or heating value-based emissions limits in the final rule, especially when the unit is operated at turndown for extended periods (*e.g.,* for 20 days or more compared to the 30-day averaging time). As the need for an alternative limit appears to be limited to a few process heaters and the optimal O_2 concentration is expected to vary, based on fuel gas composition, we determined that a site-specific emissions limit was the best approach to account for these extended turndown conditions. As such, the final rule provides owners and operators that have a process heater operating in turndown for an extended period of time the option of developing a site-specific emissions limit that would apply to those operating conditions and requesting approval from the Administrator to use that limit.

For process heaters between 40 and 100 MMBtu/hr capacity that do not install a NO_X CEMS, turndown is also expected to be an issue with respect to achieving the O_2 operating limit. As described above, higher O_2 concentrations are generally needed to maintain flame stability at low firing rates. To address potential turndown compliance issues with the O_2 operating limit, we have provided an allowance for process heater owners or operators to develop an O_2 operating curve to provide different O_2 operating limits based on the firing rate of the process heater. If a single O_2 operating limit is established, it must be determined when the process heater is being fired at 70 percent or more of capacity (*i.e.,* far from turndown conditions). For process heaters that routinely operate at less than 50 percent of design capacity and require additional O_2 to maintain flame stability, a separate O_2 operating limit should be established for turndown by conducting a second performance test while the unit is operating at less than 50 percent of capacity. Additional performance tests can be conducted to develop O_2 operating limits for additional operating ranges.

Comment: Several commenters requested that the EPA revise the emissions limits for co-fired process heaters or remove the limits for co-fired process heaters from this rulemaking and address them at a later date due to lack of sufficient data to set an achievable emissions limit. One commenter provided a white paper to support higher emissions limits. Commenters also asserted that the averaging time for the weighted average emission rate should be extended to 365 days. One commenter noted that the notation ''$E_{NOx,hour}$'' in Equation 3 was confusing since the purpose of the equation was to determine the daily emission rate.

Response: The final June 2008 rule included only one emissions limit for all co-fired process heaters, and Industry Petitioners asserted that differences in the configuration and operation of different types of process heaters warranted different emissions limits. The proposed amendments introduced two specific emissions limits for co-fired process heaters, one based on vendor guarantees for the burners and one based on an average NO_X concentration for a combination of fuel gas and fuel oil. We note that, for purposes of this rule, a co-fired process heater is defined as a process heater that employs burners that are designed to be supplied by both gaseous and liquid fuels. In other words, co-fired process heaters are designed to routinely fire both oil and gas in the same burner. These do not include burners that are designed to burn gas, but have supplemental oil firing capability that is not routinely used (*i.e.,* emergency oil back-up).

To respond to the comments requesting higher emissions limits for co-fired process heaters, we reviewed the white paper provided by one commenter (submitted as an attachment to Docket Item No. EPA–HQ–OAR–2007–0011–0308), as well as additional burner emissions test data provided by another commenter[5] (conducted under well-controlled conditions using best available ultra-low NO_X burner technologies at the manufacturer's testing facility). This information indicates that, for co-fired natural draft process heaters, a daily average emissions limit calculated based on a limit of 0.06 lb/MMBtu for the gas portion of the firing and 0.35 lb/MMBtu for the oil portion of the firing is achievable. Similarly, the information indicates that, for co-fired forced draft process heaters, a daily average emissions limit calculated based on a limit of 0.11 lb/MMBtu for the gas portion of the firing and 0.40 lb/MMBtu for the oil portion of the firing is achievable. As noted above, these values are based on burner performance tests, which are considered a better source of information than the vendor guarantees that were relied upon to develop the proposed emissions limit. Therefore, we are revising the NO_X emissions limits for co-fired process heaters to those described above. We note that we have revised the concentration-based NO_X emissions limits to be on a 30-day average basis (same as the limits for gas-fired process heaters). We have also revised the nomenclature of the daily average emissions limit in Equations 3 and 4 (proposed Equation 3) to be clear that we intend the limit to be determined on a daily basis rather than on an hourly basis.

We also note that the burner performance tests were conducted in a controlled environment at the burner manufacturer's full-scale facilities. While it is incumbent on the owner or operator of an affected process heater to control certain operating parameters, such as excess O_2 concentrations, to the

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[5] The commenter providing this data asserted that it is CBI. We will follow our CBI regulations in 40 CFR part 2 in handling this data. The data has been placed in the docket, but is not publicly available.

extent possible, we recognize that the performance limits in the final amendments are based on limited data, none of which are direct test data for a co-fired process heater operated at a petroleum refinery. We conclude that the low-NO_X burner technologies exist, are demonstrated and are cost effective for co-fired process heaters and they are, therefore, BSER for co-fired process heaters. However, as the performance limits are based on limited operational data, we also conclude that it is reasonable to provide an alternative, site-specific limit in the event that factors outside the influence of the burner design and operation (such as nitrogen content in the fuel oil) suggests the emission limits in the final rule are inappropriate for a specific application. Consequently, co-fired process heaters that cannot meet the limits specified above, can request approval for a site-specific emissions limit, as allowed above, for process heaters that operate for extended periods under turndown.

B. Flares

Comment: Several commenters asserted that routine connections to a flare should not be considered modifications of the flare because they do not change the maximum physical capacity of the flare and do not generally increase emissions. One commenter asserted that the 40 CFR part 60, subpart A General Provisions in 40 CFR 60.14 can and should apply to flares, so a special modification provision for flares in 40 CFR part 60, subpart Ja is unnecessary. Commenters noted that some connections to the flare have the primary purpose of reducing emissions, which has been excluded under 40 CFR 60.14(e)(5), a paragraph that is not limited to pollutants ''to which the standard is applicable.'' One commenter noted that a single project may remove some connections and add others such that the net emissions could actually be reduced. Another commenter asserted that an increase in flow should not be considered a modification because flow is not a regulated pollutant.

Instead, commenters asserted that the modification provision for a flare should focus on physical and operational changes that increase emissions from the flare. One commenter suggested that the EPA should focus the flare modification provision on connections that provide a primary/routine flow from a process unit to the flare. Other commenters suggested that the flare modification provision should be focused on VOC and SO_2 emissions and should only include connections that result in a net increase of those pollutants emitted ''during normal operations'' and connections that cause an increase in the total volume of gas containing VOC or sulfur compounds under standard conditions that could reach the flare.

Response: The agency made a conscious decision to promulgate a separate provision for a flare modification in 40 CFR part 60, subpart Ja (see 40 CFR 60.14(f)) because flares are operated differently from other refinery process units, making it difficult to apply the modification provision in the General Provisions (40 CFR 60.14) to them. The physical capacity of a flare is based on the amount of gas potentially discharged to a flare as a result of emergency relief. Refiners frequently make connections to existing flares that result in emissions increases at the flares, but may never approach the physical capacity of the flare system. Contrary to commenters' assertions, the flare modification provision in 40 CFR 60.100a(c) does meet the statutory definition of ''modification'' in CAA section 111(a)(4), which is ''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.'' It is axiomatic that the connections to the flare described in 40 CFR 60.100a(c) qualify as physical or operational changes to the flare. Additionally, we explained in the proposed rule how these connections also resulted in emissions increases from the flare (see 73 FR 78529). Thus, these types of new connections of refinery process units (including ancillary equipment) and fuel gas systems to the flare qualify as a ''modification'' of the flare and trigger subpart Ja applicability for the flare.

Those connections we identified that do not increase emissions from the flare were specifically excluded from triggering 40 CFR part 60, subpart Ja applicability under this same provision (see 40 CFR 60.100a(c)(1)). Specifically, we proposed on December 22, 2008, that the following types of connections to a flare would not be considered a modification of the flare: (1) Connections made to install monitoring systems to the flares; (2) connections made to install a flare gas recovery system; (3) connections made to replace or upgrade existing pressure relief or safety valves, provided the new pressure relief or safety valve has a set point opening pressure no lower and an internal diameter no greater than the existing equipment being replaced or upgraded; and (4) replacing piping or moving an existing connection from a refinery process unit to a new location in the same flare, provided the new pipe diameter is less than or equal to the diameter of the pipe/connection being replaced/moved. While we agree that there may be other connections to a flare that would not result in an emissions increase from the flare (see response to the next comment for specific details), we disagree with the commenters that the flare modification provision should be further limited beyond what is already provided in the provision.

We disagree with commenters that we must consider the ''net'' emissions from the process unit and the flare when determining whether a flare is modified. The affected facility is the flare and does not include the process units that are tied into the flare header system. *See Asarco* v. *EPA,* 578 F.2d 319, 325 (D.C. Cir. 1978) (holding that emission increases had to be determined based on emissions from the affected facility). We also disagree that a modification determination should be limited to emissions increases of VOC or SO_2. Flares are known to emit VOC, SO_2, carbon monoxide (CO), PM and NO_X, as well as other air pollutants, all of which are relevant when determining whether a flare has been modified. See CAA section 111(a)(4). That is, we consider the standards for flares to be emission standards for VOC, SO_2, CO, PM and NO_X. See, generally, 73 FR 35838, 35842, 35854–35856 (June 24, 2008); 73 FR 78522, 78533 (December 22, 2008), as well as Table 4 of this preamble. Using the flare to control VOC emissions at other refinery process units will increase CO, PM and NO_X emissions from the flare and are, therefore, considered modifications of the flare, even if there is a net reduction in VOC emissions at the refinery.

In evaluating whether a flare has been modified, we consider increases in flow to the flare to be directly indicative of increased emissions from the flare. While we agree that ''flow'' is not a pollutant, we evaluated flow limits as a means to reduce SO_2, VOC, CO, NO_X and other emissions from the flare. The emissions from the flare are very difficult, if not impossible, to measure accurately, but flow to the flare can be measured, and the flow to the flare generates SO_2, VOC, CO, PM, NO_X and other emissions. Therefore, a physical or operational change to a flare that causes an increase of flow to the flare will increase emissions of at least one of these pollutants and is considered a modification of the flare.

Comment: Many commenters responded to the EPA's request for comment on types of connections that do not result in an increase in emissions from a flare. The commenters suggested numerous specific connections that should not be considered modifications, including:

(1) Connections made to upgrade or enhance (not just to install) a flare gas recovery system;

(2) Connections made for flare gas sulfur removal;

(3) Connections made to install back-up equipment;

(4) Flare interconnects;

(5) All emergency pressure relief valve connections from existing equipment;

(6) Connections of monitoring system purge gases and analyzer exhausts or closed vent sampling systems;

(7) Purge and clearing vapors, block and bleeder vents and other uncombusted vapors where the flare is the control device;

(8) Connections made to comply with other federal, state or local rules where the flare is the control device;

(9) Connections of ''unregulated gases'' such as hydrogen, nitrogen, ammonia, other non-hydrocarbon gases or natural gas or any connection that is not fuel gas;

(10) New connections upstream of an existing flare gas recovery system, provided the new connections do not compromise or exceed the flare gas recovery system's capacity;

(11) Any new, moved or replaced piping or pressure relief valve connections that do not result in a net increase in emissions from the flare, regardless of piping or pressure relief valve size;

(12) Vapors from tanks used to store sweet or treated products;

(13) Temporary connections for purging existing equipment, as these are essentially ''existing'' connections; and

(14) Connections of safety instrumentation systems (SIS) described under Occupational Safety and Health Administration (OSHA) process safety standards at 29 CFR 1910.119, the EPA's risk management program at 49 CFR 68 and/or American National Standards Institute (ANSI)/International Society of Automation (ISA)-84.00.01–2004.

Response: We carefully reviewed the commenters' suggested changes to the flare modification provision to determine whether there are additional connections that should not be considered modifications to the flare. We agree that the first four connections in the commenters' list should not be considered modifications of a flare. Projects to upgrade or enhance components of a flare gas recovery system (*e.g.,* addition of compressors or recycle lines) will improve the operation of the flare gas recovery system, and connections to these additional components will not result in increased emissions. Connections made for removal of sulfur from flare gas (Item 2 above) will generally result in a slight decrease in volumetric flow and a large decrease in emissions of SO_2. Connections made to install back-up or redundant equipment (Item 3 above), such as a back-up compressor, will result in fewer released emissions if there is a malfunction in the main equipment.

The request to exclude flare interconnections (Item 4 above) is a complicated issue because interconnecting two separate flares alters what we consider to be the affected facility. The definition of ''flare'' specifically includes the flare gas header system as part of the flare. Prior to interconnecting the flares, presumably each flare header system is independent, and there would be two separate ''flares,'' each of which could potentially be an affected facility subject to 40 CFR part 60, subpart Ja. However, because the flare includes the flare header system, we consider that an interconnected flare system is a single affected facility, and we have amended the definition of ''flare'' for clarity. We agree that interconnections between flares will not alter the cumulative amount of gas being flared (*i.e.,* interconnecting two flares does not result in an emissions increase relative to the two single flares prior to interconnection). We also see cases where the emissions from a single flare tip will likely be reduced due to the flare interconnect. For example, when a large release event occurs, this gas will now flow to both of the interconnected flares rather than a single flare. The maximum emission rate for the original single flare actually decreases, while the combined emissions from both flares is the same quantity as prior to the interconnection. Considering this, we agree that the interconnection of two flares does not necessarily result in a modification of the flare and we have specifically excluded flare interconnections from the modification provisions.

However, we also clarify in this response that when a flare that is subject to 40 CFR part 60, subpart Ja is interconnected with a flare that is not subject to subpart Ja, then the resulting interconnected flare is subject to subpart Ja. That is, the only case in which an interconnection between two (or more) flares results in a combined, interconnected flare that is not subject to subpart Ja is when none of the original individual flares were subject to subpart Ja. Additionally, we note that if a new connection is made to the interconnected flare, then the flare (including each individual flare tip within the interconnected flare header system) is modified and becomes an affected facility subject to subpart Ja.

While we agree that connections that do not increase the emissions from the flare should not trigger a modification, we disagree with the commenter that their other suggested connections do not increase the flare's emissions at the time gases are discharged via the new connection. Each of the commenters' suggestions is discussed in the following paragraphs.

We previously proposed an exemption for emergency pressure relief valve connections from existing equipment (Item 5 above) if they replace or upgrade existing equipment and do not increase the instantaneous release rate to the flare (*i.e.,* the new pressure relief valve has a pressure set point and diameter no greater than the equipment being replaced). As stated previously in this preamble, we are finalizing that amendment, as proposed. However, new connections, even if they are made to ''existing equipment,'' will result in an increase in flow to the flare during periods of process upset that cause the pressure relief valve to open.

Connections of monitoring system purge gases and analyzer exhausts or closed vent sampling systems (Item 6 above) will increase the emissions from the flare. Similarly, connections of purge and clearing vapors and block and bleeder vents (Item 7 above), also trigger a modification of the flare because the increase of gas flow to the flare will increase the emissions from the flare.

We recognize that connections to a flare may be made to comply with other federal, state or local rules where the flare is an emissions control device (Item 8 above). In fact, nearly all flares could be considered ''control devices.'' We agree that using a flare as an emissions control device is preferable to venting the process unit to the atmosphere. However, while using the flare as an emissions control device does decrease emissions from the process unit being controlled, the increase of gas flow to the flare will increase the emissions from the flare. Therefore, a connection from a process unit to a flare for use as an emissions control device results in a modification of that flare.

Comments suggesting that connections of ''unregulated gases'' such as hydrogen, nitrogen, ammonia, other non-hydrocarbon gases or natural gas or connections that are not ''fuel gas,'' should not be considered a modification of the flare (Item 9 above) are in conflict with the statutory definition of ''modification.'' Each of the streams mentioned by the commenter, when directed to a flare, will increase emissions of at least one pollutant (either PM, CO or NO_X) from the flare (all of which the standard is intended to reduce). That is, we reiterate that we consider the standards for flares to be emission standards for VOC, SO_2, CO, PM and NO_X. As such, we do not agree that the types of gas streams suggested by the commenters should be exempt from the modification determination.

New connections upstream of an existing flare gas recovery system (Item 10 above) will increase the likelihood of an event that would cause an exceedance of the flare gas recovery system's capacity (even if the new connections ''do not exceed the flare gas recovery system's capacity'' under normal conditions), and the amount of gases sent to the flare would increase as a result of such an event, thereby increasing the emissions from the flare.

We reiterate that we proposed an exemption for any moved or replaced piping or pressure relief valve connections of the same size. However, we disagree with the commenter's suggestion that any ''new, moved, or replaced piping or pressure relief valve connections that do not result in a net increase in emissions from the flare regardless of piping or pressure relief valve size'' should be exempted (Item 11 above). The premise of the suggested amendment is that new or larger connections somehow will not increase emissions from the flare. We have discussed new connections previously, so we will concentrate on the ''regardless of piping or pressure relief valve size'' comment in this paragraph. First, the size of the pressure relief valve or piping does correlate to the discharge rate to the flare, with larger pressure relief valves or larger diameter piping allowing higher discharge rates to the flare at a given pressure. In fact, larger pressure relief valves and larger diameter pipes are specifically designed to allow higher flow rates to the flare. Second, higher flow rates will lead to higher emission rates. For a pressure relief event that occurs for several hours, the flow rate to the flare during the first hour of relief using the larger pressure relief valve or larger diameter piping will be larger than the flow rate experienced using the smaller pressure relief valve or smaller diameter piping and will result in higher emissions from the flare. Therefore, we reject the notion that larger diameter pipes and larger pressure relief valves do not increase the emissions rate from the flare during a release event. We are finalizing the proposed exemptions for moved or replaced piping or pressure relief valves with the size and design restrictions for the new piping or pressure relief valves as proposed on December 22, 2008.

Commenters suggested that connections of vapors from tanks used to store sweet or treated products (Item 12 above) should not be modifications because those gas streams have less than 162 ppmv H_2S. We reiterate that SO_2 is not the only pollutant emitted from flares and that the additional flow of sweet gases will increase the emissions of at least one pollutant from the flare, so we are not exempting these types of connections to the flare from the 40 CFR part 60, subpart Ja flare modification provision. However, we have amended the sulfur monitoring requirements for flares to exempt vapors from tanks used to store sweet or treated products from the flare sulfur monitoring requirements. This monitoring exemption is justified because it is not needed for the purposes of a root cause analysis or other compliance purpose. For these sweet vapors, the flow rate root cause analysis threshold will be exceeded well before the SO_2 root cause analysis threshold.

We carefully considered temporary connections for purging existing equipment (Item 13 above), but we failed to see how these temporary connections are essentially ''existing connections.'' According to the commenters, ''maintenance gases have been routed in some form or other to the flare for years, and the temporary tie-in to accomplish that is not a change and is not an increase in emissions when viewed from a before and after perspective.'' If the connections already exist, then opening an existing valve to allow for this type of purging would not trigger a flare modification. If the connection is being relocated and the piping used is the same diameter as the pre-existing connection, then this scenario is adequately covered by the proposed exclusion for relocated connections. However, if a new connection is made specifically to purge an existing piece of equipment, this purge gas unequivocally represents additional gas flow sent to the flare that did not exist and could not exist prior to the connection being made. Again, we consider that the increase in gas flow to the flare will result in an increase in emissions of at least one pollutant from the flare. As such, no exemption is provided for new connections to existing equipment, regardless if these connections are temporary or permanent. We also find that these types of flows should be expressly considered in the flare management plan and that flaring from these ''temporary'' connections should be minimized to the extent practicable.

The impact of connections of SIS described under OSHA process safety standards at 29 CFR 1910.119, the EPA's risk management program at 49 CFR 68 and ANSI/ISA–84.00.01–2004 (Item 14 above) should be evaluated on a case-by-case basis to determine whether these connections result in a flare modification. We expect that, if these connections are made for flare monitoring purposes, these connections are already excluded in the exemption for flare monitoring systems. If the ''SIS'' are process unit analyzers and the new connections are being made to connect the analyzer exhaust to the flare, these connections would be considered a modification, as previously discussed. The commenter may also be referring to new connections for additional pressure relief valves identified in the safety reviews required by the cited rules, which we would consider to be a modification of the flare.

Following all of the above review and analysis, we are finalizing three of the connections, as proposed, adding three of the connections requested by commenters and revising one of the proposed connections as requested by commenters in 40 CFR 60.100a(c)(1). Thus, the following seven types of connections are not considered a modification of the flare:

(1) Connections made to install monitoring systems to the flare.

(2) Connections made to install a flare gas recovery system or connections made to upgrade or enhance components of a flare gas recovery system (*e.g.,* addition of compressors or recycle lines).

(3) Connections made to replace or upgrade existing pressure relief or safety valves, provided the new pressure relief or safety valve has a set point opening pressure no lower and an internal diameter no greater than the existing equipment being replaced or upgraded.

(4) Connections that interconnect two or more flares.

(5) Connections made for flare gas sulfur removal.

(6) Connections made to install back-up (redundant) equipment associated with the flare (such as a back-up compressor) that does not increase the capacity of the flare.

(7) Replacing piping or moving an existing connection from a refinery process unit to a new location in the same flare, provided the new pipe diameter is less than or equal to the

diameter of the pipe/connection being replaced/moved.

Comment: Several commenters suggested that *de minimis* emission increases and net emission decreases resulting from new connections to a flare made to control and combust fugitive emissions such as leaks from compressor seals, valves or pumps, should not be considered modifications of a flare. One commenter suggested allowing site-specific exemptions for connections that do not increase emissions or that result in a *de minimis* emissions increase. However, another commenter objected to setting a *de minimis* emissions increase to determine whether a change to a flare is a modification and stated that allowing a *de minimis* approach would cause confusion over the applicability of 40 CFR part 60, subpart Ja because flare emissions are difficult to estimate.

Response: In the preamble to our proposed amendments, the EPA specifically requested comment on using the *de minimis* exception in the flare modification provision. 73 FR 78522, 78529. Industry Petitioners had suggested some type of *de minimis* emissions increase should be allowed without triggering 40 CFR part 60, subpart Ja applicability. *Id.* The EPA acknowledged that these exceptions are ''permissible but not required'' under the modification provision in the CAA. *Id.* The EPA also stated: ''We request comments on a *de minimis* approach and on specific changes that may occur to flares that will result in *de minimis* increases in emissions. We also request comments on the type, number, and amount of emissions that would be considered *de minimis.'' Id.*

Industry Petitioners continue to recommend that any emissions increases resulting from ''routine connections'' to the flare system ''will be *de minimis''* and should not trigger 40 CFR part 60, subpart Ja applicability at the flare, but they have not provided the comments or data requested in the proposal preamble that the EPA could consider to evaluate the impacts of such an approach. Docket Item No. EPA–HQ–OAR–2007–0011–0311 (second attachment), pg 20. Industry Petitioners again suggest that the EPA exercise its authority and ''authorize exceptions from otherwise clear statutory mandates'' by promulgating *de minimis* exemptions for the flare modification provision. *Id.; Alabama Power Co.* v. *Costle,* 636 F.2d 323, 360 (D.C. Cir. 1979). As explained in *Alabama Power,* the *de minimis* exception allows agency flexibility in interpreting a statute to prevent ''pointless expenditures of effort.'' *Id.* However, as Industry Petitioners recognize, nothing mandates that the EPA use its *de minimis* authority in any given instance, and courts especially recognize the significant deference due an agency's use of a *de minimis* exception. *Id.* at 400; *Shays* v. *Federal Election Com'n,* 414 F.3d 76, 113 (D.C. Cir. 2005); *Environmental Defense Fund, Inc.* v. *EPA,* 82 F.3d 451, 466 (D.C. Cir. 1996); *Ass'n of Admin. Law Judges* v. *Fed. Labor Relations Auth.,* 397 F.3d 957, 961 (D.C. Cir. 2005).

In exercising that discretion, the EPA must consider the cautionary advice it received from the *Alabama* Court regarding its use of the *de minimis* exception: ''EPA must take into account in any action * * * that this exemption authority is narrow in reach and tightly bounded by the need to show that the situation is genuinely *de minimis.'' Id.* at 361. The Court also noted that exemptions from ''the clear commands of a regulatory statute, though sometimes permitted, are not favored.'' *Id.* at 358. The EPA must exercise this authority cautiously, and only in those circumstances that truly warrant its application.

The EPA has found no basis for promulgating a *de minimis* exception to the flare modification provision. Despite its assertions, Industry Petitioners have still provided no data to support a finding that the emissions increases resulting from the alleged ''routine connections'' to a flare system are truly ''trivial or [of] no value.'' Docket Item No. EPA–HQ–OAR–2007–0011–0311 (second attachment), pg 20. Without the requested information showing that ''the situation is genuinely *de minimis,'' Alabama Power,* 636 F.2d at 361 and, therefore, warrants this kind of exception, we believe such an exemption would be inappropriate.

Additionally, Industry Petitioners' example that ''venting a new small storage tank to a flare system * * * easily would cost a typical refinery tens of millions of dollars'' since ''the *entire* flare system'' (emphasis in original) would be subject to subpart Ja is unavailing for its argument that the EPA should promulgate a *de minimis* exception for the flare modification provision. Docket Item No. EPA–HQ–OAR–2007–0011–0311 (second attachment), pg 21. As the District of Columbia Circuit specifically states in *Shays,* authority for promulgating a *de minimis* exception ''does *not* extend to a situation where the regulatory function does provide benefits, in the sense of furthering regulatory objectives, *but the agency concludes the acknowledged benefits are exceeded by the costs.'' Shays,* 414 F.3d 76, 114 (emphasis added). By focusing solely on cost, Industry Petitioners are effectively asking the agency to engage in the type of cost-benefit analysis prohibited by the *Shays* Court. Such cost analyses are improper in these types of decisions. Industry Petitioners generally focus their discussion on VOC emissions and effectively admit that connecting the small storage tank to the flare system increases emissions from the flare (*e.g.,* ''uncontrolled tank emissions would be *essentially* eliminated by combustion in a flare'' (Docket Item No. EPA–HQ–OAR–2007–0011–0311 (second attachment), pg 21, emphasis added)). Furthermore, they disregard additional emissions of NO_X and CO resulting from the combustion of these gases at the flare. Industry Petitioners also provide no data quantifying these emissions increases and, therefore, cannot demonstrate that they are ''trivial or [of] no value'' or, in other words, that the emissions increases are, in fact, *de minimis.* As releases to the flare are often event driven, one can envision situations where the release from even a small storage tank could be significant. On the other hand, the EPA sees a substantial environmental benefit in requiring controls that will reduce the cumulative emissions from a flare that becomes subject to 40 CFR part 60, subpart Ja because of any of these alleged ''routine connections.'' Thus, given the nature of releases to the flare, we determined that a *de minimis* exemption from the modification provisions for flares is unworkable and unwarranted.

Comment: One commenter stated that exempting flares[6] from the H_2S concentration limits during startup, shutdown and malfunction (SSM) events is illegal because the CAA requires continuous compliance with standards of performance promulgated under CAA section 111. See CAA sections 111(a)(1), 302(k). For support, the commenter cited *Sierra Club* v. *EPA,* 551 F.3d 1019 (DC Cir. 2008), in which the Court stated: ''When sections 112 and 302(k) are read together, then, Congress has required that there must be continuous section 112-compliant standards.'' The commenter noted that the Court found that the exemption from compliance with CAA section 112 standards during SSM events violates

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[6] The comments submitted referenced ''fuel gas combustion devices'' as the affected source when describing the exemption during SSM events. However, the exemption only applies to flares. See 40 CFR 60.103a(h). The discussion in this preamble is, therefore, focused on flares as distinguished from other types of fuel gas combustion devices that are required to comply at all times with the H_2S concentration limits in 40 CFR 60.102a(g)(1).

the CAA because the general duty to minimize emissions during SSM events is not a CAA section 112-compliant standard. The commenter asserted that the CAA also requires that a section 111-compliant standard that reflects BSER[7] be in effect at all times for flares.

The commenter further asserted that work practice standards for flares are not CAA section 111-compliant standards because this is not one of those ''limited instances'' in which CAA section 111(h) authorizes such standards. The commenter stated that the EPA must show that a standard of performance for flares is ''not feasible to prescribe or enforce'' because ''(A) a pollutant * * * cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any federal, state or local law or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations.'' See CAA section 111(h)(2). The commenter stated that neither of these exemptions appear to apply and the EPA cannot claim that it is infeasible to promulgate a standard of performance for flares,[8] so the EPA cannot set a work practice standard for flares. Thus, the commenter asserted that a CAA section 111-compliant standard does not continuously apply to flares since both the exemption from the H_2S concentration limits during SSM events and the flare work practice standards are not lawful under the CAA.

Another commenter disagreed and provided several reasons why they believe the EPA may lawfully exempt flares from the H_2S concentration limits during SSM events. First, the commenter noted that 40 CFR part 60, subpart Ja was promulgated as part of the mandatory periodic review of 40 CFR part 60, subpart J required by CAA section 111(b)(1)(B). The commenter noted that subpart J exempts a flare from the H_2S concentration limits when combusting certain gases generated during SSM events (see 40 CFR 60.104(a)(1), 60.101(e)) and stated that the record contains ''ample evidence'' to support maintaining that provision in subpart Ja. The commenter asserted that including these same provisions in subpart Ja is ''an appropriate exercise of EPA's authority to 'not review' this aspect of the existing standard in light of the efficacy of the existing standard.'' See CAA section 111(b)(1)(B).

Second, the commenter noted that the *Sierra Club* decision was largely grounded in the Court's determination that Congress amended CAA section 112 out of concern ''about the slow pace of EPA's regulation of HAPs,'' eliminating much of the EPA's discretion and requiring sources to ''meet the strictest standards'' without variance ''based on different time periods.'' The commenter further explained that the Court pointed to CAA section 112(d)(1) regarding the EPA's authority to ''distinguish among classes, types, and sizes of sources'' when promulgating CAA section 112 standards as further evidence for constraining the EPA's ability to adopt different standards applicable during SSM events. In contrast, the commenter asserted that ''Congress has expressed no such concern about EPA's efforts to implement section 111'' despite revisions to CAA section 111 in 1977 and 1990. Therefore, the commenter asserted, Congress has ''effectively ratified EPA's longstanding approach to SSM under the NSPS program,'' which includes the exemption for flares from the H_2S concentration limits during SSM events.

The commenter also asserted that, regardless of the above and despite the similar nature of the provisions in CAA sections 111 and 112, the EPA has the discretion to implement them differently ''under the markedly differently context of the NSPS program v. the MACT program.'' See *Environmental Defense* v. *Duke Energy Corp.,* 549 U.S. 561, 575–576 (2007). For example, the commenter asserted that the word ''continuous'' as used in the NSPS program could be interpreted and applied differently, as acknowledged by the Court in *National Lime Ass'n* v. *EPA,* 627 F.2d 416, 434 (DC Cir. 1980) (deferring to agency regarding the effect of ''the perplexing implications of Congress' new requirement of systems of continuous emission reduction'' on the agency's longstanding ''regulations permitting flexibility to account for startups, shutdowns, and malfunctions''). The commenter urged the EPA to exercise this discretion and ''reassert the many practical, technical and economic factors'' that justify promulgating separate standards for SSM events in the NSPS program.

Third, the commenter asserted that requiring flares to meet the H_2S concentration limits during SSM events does not represent BSER for this time period. According to the commenter, ''startup and shutdown gases are intermittent streams that cannot be cost effectively treated for sulfur removal because of their infrequent occurrence, their scattered points of generation and their variability.'' Therefore, for all of the above reasons, the commenter asserted that exempting a flare from the H_2S concentration limits when combusting certain gases generated during SSM events is lawful under CAA section 111.

Alternatively, the commenter stated that if a standard must apply during SSM events, the flare work practice standards are appropriate in lieu of the H_2S concentration limit.

Response: Regardless of whether or how the *Sierra Club* decision under CAA section 112 applies to NSPS promulgated under CAA section 111, we are promulgating final amendments for flares that include a suite of standards that apply at all times and are aimed at reducing SO_2 emissions from flares. As described previously, this suite of standards requires refineries to: (1) Develop and implement a flare management plan; (2) conduct root cause analysis and take corrective action when waste gas sent to the flare exceeds a flow rate of 500,000 scf above the baseline; (3) conduct root cause analysis and take corrective action when SO_2 emissions exceed 500 lb in a 24-hour period; and (4) optimize management of the fuel gas by limiting the short-term concentration of H_2S to 162 ppmv during normal operating conditions. Additionally, refineries must install and operate monitors for measuring sulfur and flow at the inlet of all of their flares. Together, these requirements provide CAA section 111-compliant standards that collectively cover all operating conditions of the flare.

As the commenter notes, CAA section 111(h)(1) allows the EPA to promulgate a design, equipment, work practice or operational standard or ''combination thereof,'' when ''it is not feasible to prescribe or enforce a standard of performance'' which reflects BSER for the particular affected source. CAA section 111(h)(2) defines the phrase

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[7] The commenter asserted, without providing support, that it is not BSER to exempt flares from the H_2S concentration limits during startup and shutdown events. The commenter also stated that the EPA, at a minimum, must demonstrate how the exemption from the H_2S concentration limits during SSM events does, in fact, represent BSER, but the commenter stated that the EPA has failed to make this demonstration.

[8] The commenter cited the EPA's rationale for proposing work practice standards for flaring in which we state: ''It is not feasible to prescribe or enforce a standard of performance for these sources because either the pollution prevention measures eliminate the emission source, so that there are no emissions to capture and convey, or the emissions are so transient, and in some cases, occur so randomly, that the application of a measurement methodology to these sources is not technically and economically practical.'' 72 FR 27178, 27194–27195 (May 14, 2007). In response, the commenter stated: ''[T]he plain language of the Act recognizes that standards of performance leading to the 'capture' of emissions are not infeasible [citation omitted], and EPA has proposed to apply measurement methodologies to flares in spite of the transience of their emissions.''

''not feasible to prescribe or enforce a standard of performance'' as ''any situation in which the Administrator determines that * * * a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or * * * the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations.''

We have determined that flares meet the criteria set forth in CAA section 111(h)(2)(A) because emissions from a flare do not occur ''through a conveyance designed and constructed to emit or capture such pollutant.'' Gases are conveyed to the flare for destruction, and combustion products such as SO_2 are not created until combustion occurs, which happens in the flame that burns outside of the flare tip. In other words, the SO_2, NO_X, PM, CO, VOC and other pollutants generated from burning the gases are only created once the gases pass through the flare and come into contact with the flame burning on the outside of the flare. The flare itself is not a ''conveyance'' that is ''emitting'' or ''capturing'' these pollutants; instead, it is a structure designed to combust the gases in the open air. Thus, setting a standard of performance for SO_2 (and other pollutants) is not ''feasible,'' allowing the EPA to instead promulgate standards under CAA section 111(h), which will collectively limit emissions from the flare.

The EPA previously promulgated a standard of performance for SO_2 emissions for fuel gas combustion devices which also applied to flares. 39 FR 9308, 9315 (March 8, 1974). The standard is expressed as an H_2S concentration limit because it was developed as an alternative to measuring the SO_2 concentration in the stack gases exiting fuel gas combustion devices other than flares (*i.e.,* boilers and process heaters). That approach is appropriate for fuel gas combustion devices other than flares because measuring the H_2S in the fuel gas combusted in those devices is directly indicative of the SO_2 emitted from the exhaust stacks of those other devices. As explained in section III of this preamble, we are, for the first time, designating flares as their own affected facility. As such, in finalizing these amendments for flares, we considered whether we could also apply a standard of performance for SO_2 emissions, expressed as an H_2S concentration limit or a total sulfur limit at the inlet to the flare. However, as explained above, flares are substantially different from other fuel gas combustion devices so that this approach is not workable for flares. For example, SO_2 emissions from a flare are dependent on many factors, including the flow rates of all gases sent to the flare, the total sulfur content of all gases sent to the flare and the combustion efficiency at the flare. Each of these factors is also dependent on many variables. For example, combustion efficiency at the flare is dependent upon the flammability of the gases entering the flare, the turbulence at the flare,[9] the wind speed and wind direction and the presence of other pollutants in the gases that can react with the sulfur to form sulfur-containing pollutants other than SO_2. Since so many factors affect the potential formation of SO_2 emissions outside the flare tip, we realized that we could not properly derive an H_2S concentration limit or a total sulfur limit at the flare inlet that would directly correlate with those SO_2 emissions. Thus, we determined that we cannot set a standard of performance for SO_2 emissions at the flare.

However, we still recognize that reducing the amount of sulfur that is sent to a flare will reduce the SO_2 emissions at the flare. Even with the uncertainty described above, we understand the importance of refineries managing the fuel gas sent to their flares in a way that minimizes the sulfur content so as to ultimately minimize the SO_2 emissions. Rather than eliminate the H_2S concentration limit altogether, we are instead requiring under CAA section 111(h) that refineries limit the short-term concentration of H_2S to 162 ppmv in the fuel gas sent to flares during normal operating conditions. Refineries rely on various methods for optimizing the management of fuel gas, including the use of amine treatment and flare gas recovery systems. Amine treatment removes the H_2S from the flare gas that generates the pollutants before the gas is sent to the flare. Flare gas recovery systems remove the flare gas altogether and instead treat this gas in a fuel gas treatment system to be used elsewhere as fuel gas in the refinery. Requiring refineries to meet this concentration limit at the flare ensures that the fuel gas has been adequately treated and managed such that it can be used as fuel gas in the fuel gas system elsewhere in the refinery. We are not requiring refineries to meet this limit during other periods of operation because flare gas recovery systems that capture gases prior to amine treatment can be quickly overwhelmed and fail to properly function during high fuel gas flows. Thus, requiring that flares meet this H_2S concentration limit during periods when high fuel gas flows would likely overwhelm these flare gas recovery systems would not fully address the circumstances refineries face in managing these high flow periods. Designing flare gas recovery systems to capture the full range of gas flows to the flare would not only require the ability to predict the full range of gas flows in the flare headers, but also would require refiners to install recovery compressors in a staged fashion such that all events causing high gas flows could be captured and managed, neither of which are practical. Therefore, promulgating flare requirements that include the H_2S fuel gas concentration limit during normal operating conditions, coupled with requirements for refineries to develop and implement a flare management plan and conduct root cause analyses and take corrective action when waste gas sent to the flare exceeds a flow rate of 500,000 scf above the baseline or 500 lb of SO_2 in a 24-hour period, recognizes these unique circumstances while still requiring the refinery to take all reasonable measures for reducing or eliminating the flow and sulfur content of gases being sent to the flares.

We are aware that numeric SO_2 emission limits for flares have been established under state law and in Federal Implementation Plan (FIP) regulatory requirements. Those source-specific circumstances differ markedly from this nationally applicable rulemaking, necessitating different decisions in two very different circumstances. For example, the EPA's SO_2 FIP for the Billings/Laurel, Montana area includes a SO_2 emission limit of 150 lb of SO_2 per 3 hours for four sources that apply to the flares at all times. See 40 CFR 52.1392(d)(2)(i), (e)(2)(i), (f)(2)(i) and (g)(2)(i). These source-specific limits were appropriately based on dispersion modeling in the Billings/Laurel area to determine what was needed to meet national ambient air quality standards (NAAQS) for SO_2 in the Billings/Laurel area. In contrast, the nationally applicable standards and requirements we are promulgating in this rule must represent the BSER achievable for an entire industry sector scattered across the entire country. This requires that we consider costs and other non-air quality factors that affect all petroleum refineries nationwide in making that decision and not just as applied to a

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[9] Turbulence is needed to insure good mixing at the flare, but is affected by whether the flare is assisted with air or steam or non-assisted.

particular group of sources in a particular location.

Additionally, those four sources subject to the Billings/Laurel FIP demonstrate compliance with the 150 lb SO_2/3-hour emission limit by measuring the total sulfur concentration and volumetric flow rate of the gas stream at the inlet to the flare. See 40 CFR 52.1392(d)(2)(ii), (e)(2)(ii), (f)(2)(ii), (g)(2)(ii) and (h). Since the FIP must include emissions limits that insure attainment and maintenance of the NAAQS in the Billings/Laurel area, it was appropriate, in setting the standards for the Billings/Laurel FIP, to conservatively assume that 100 percent of the sulfur in the gases discharged to the flare is converted to SO_2, and based on this conversion, set the numeric limit as a value that is not to be exceeded. However, that same assumption is not appropriate when setting national standards for flares. Instead, we must consider the many factors affecting the formation of SO_2 at the flare tip and how these factors affect how much of the sulfur in the gases sent into the flare actually converts to SO_2. Therefore, although setting such source-specific limits was appropriate to satisfy what the modeling showed was necessary to meet the SO_2 NAAQS in the Billings/Laurel area, a different analysis and standard is appropriate for a national rulemaking.

Therefore, for the reasons discussed above, the EPA is finalizing this collective set of CAA section 111(h)-compliant standards for flares, based on our interpretation of CAA section 111(h) as it applies to flares.

Comment: Numerous commenters asserted that the long-term 60 ppmv H_2S fuel gas concentration limit is not cost effective for flares and, therefore, not BSER for flares. The commenters noted that the EPA did not include costs for compressors, additional amine units and sulfur recovery units, and one commenter stated that the EPA did not consider the range of costs that are incurred by individual refineries. Commenters also asserted that the EPA overstated emission reductions by using 162 ppmv H_2S as a baseline because many refinery streams currently sent to the flare contain H_2S concentrations below 162 ppmv, so 162 ppmv H_2S does not reflect long-term performance. Commenters noted that the British thermal units (Btu) content of flare gas is highly variable and generally lower than that used by the EPA, so the EPA's analysis overestimated the value of the recovered flare gas. One commenter noted that the EPA should have considered consent decree requirements in the baseline SO_2 emissions estimates.

One commenter stated that the long-term 60 ppmv H_2S fuel gas concentration limit could preclude some refineries from processing high-sulfur crude oils, thereby limiting refining production capacity. Another commenter noted that many flares will receive both fuel gas and process upset gas, so it would be impossible to determine if an exceedance is caused by the regulated fuel gas or by the exempt gas. The commenter recommended that the EPA apply the long-term 60 ppmv H_2S fuel gas concentration limit only to fuel gas combusted in process heaters, boilers and similar fuel gas combustion devices, and not to flares, or that the EPA allow Alternative Monitoring Plans to demonstrate compliance with the emissions limits for non-exempt gas streams upstream of the flare header.

Response: We acknowledge that, at proposal, we determined that a long-term 60 ppmv H_2S fuel gas concentration limit was cost effective primarily for process heaters, boilers and other fuel gas combustion devices that are fed by the refinery's fuel gas system. Based on the typical configuration at a refinery, adding one new fuel gas combustion device to the fuel gas system would essentially require the owner or operator to limit the long-term concentration of H_2S in the entire fuel gas system to 60 ppmv, so emission reductions would result from all fuel gas combustion devices tied to that fuel gas system. Upon review of the BSER analysis conducted at proposal for fuel gas combustion devices, we now realize that the analysis is not applicable to flares (See Docket Item No. EPA–HQ–OAR–2007–0011–0289).

Moreover, since we are regulating flares separately from other fuel gas combustion devices in this final rule, we should separately consider whether a long-term H_2S concentration limit is appropriate for fuel gas sent to flares.

In developing the suite of CAA section 111(h) standards for flares, we considered whether refineries should be required to optimize management of their fuel gas by limiting the long-term H_2S concentration to 60 ppmv in addition to the short-term H_2S concentration of 162 ppmv during normal operating conditions. We determined that, for refineries to demonstrate that their fuel gas complies with a long-term H_2S concentration of 60 ppmv, refineries would have to install a flare gas recovery system (which was not needed for other fuel gas combustion devices) and then upgrade the fuel gas desulfurization system. Alternatively, refineries would have to treat the recovered fuel gas to limit the long-term concentration of H_2S to 60 ppmv with new amine treatment units on each flare.

While some of the costs provided by the commenters did not include the value of the recovered gas and appeared, at times, to include equipment not necessarily required by the regulation, we generally agree with the commenters, based on our own cost estimates, that optimizing management of the fuel gas system to limit the long-term concentration of H_2S to 60 ppmv is not cost effective for flares (see Table 4 below). We note that the costs provided by the commenters and the costs and emissions reductions in our analysis are the incremental costs and emissions reductions of going from the short-term 162 ppmv H_2S concentration to a combined short-term 162 ppmv H_2S concentration and long-term 60 ppmv H_2S concentration. While we are aware that some consent decrees require refineries to limit the concentration of H_2S in the fuel gas to levels lower than the short-term 162 ppmv H_2S concentration, our baseline when evaluating the impacts of a national standard (in this case, 40 CFR part 60, subpart Ja) is the national set of requirements to which an affected flare would be subject in the absence of subpart Ja (*i.e.,* the short-term 162 ppmv H_2S concentration limit in 40 CFR part 60, subpart J).

TABLE 4—NATIONAL FIFTH YEAR IMPACTS OF MEETING A LONG-TERM 60 PPMV H_2S CONCENTRATION FOR FLARES SUBJECT TO 40 CFR PART 60, SUBPART JA

	Capital cost ($1,000)	Total annual cost ($1,000/yr) [a]	Emission reduction (tons SO_2/yr) [b]	Emission reduction (tons NO_X/yr) [b]	Emission reduction (tons VOC/yr) [b]	Cost effectiveness ($/ton)
New	80,000	15,000	6	34	130	84,000

TABLE 4—NATIONAL FIFTH YEAR IMPACTS OF MEETING A LONG-TERM 60 PPMV H_2S CONCENTRATION FOR FLARES SUBJECT TO 40 CFR PART 60, SUBPART JA—Continued

	Capital cost ($1,000)	Total annual cost ($1,000/yr) [a]	Emission reduction (tons SO_2/yr) [b]	Emission reduction (tons NO_X/yr) [b]	Emission reduction (tons VOC/yr) [b]	Cost effectiveness ($/ton)
Modified/Reconstructed	860,000	160,000	53	310	1,200	100,000

[a] Because of the heat content of recovered gas, each scf of recovered gas is assumed to offset one scf of natural gas; a value of $5/10,000 scf of natural gas was used to estimate recovery credit.

[b] These emission reductions are based on flares already meeting the short-term 162 ppmv H_2S fuel gas concentration limit in 40 CFR part 60, subpart J (*i.e.,* these are the incremental emission reductions achieved from a baseline of optimizing management of the fuel gas system to limit the short-term H_2S concentration in the fuel gas to 162 ppmv to the originally proposed combined short-term 162 ppmv H_2S concentration and long-term 60 ppmv H_2S concentration in the fuel gas).

Comment: Several commenters addressed the EPA's request for comment on ''the equivalency of the subpart Ja requirements as proposed to be amended today and the SCAQMD Rule 1118'' and ''whether EPA could deem a facility in compliance with subpart Ja as proposed to be amended today if that facility was found to be in compliance with SCAQMD Rule 1118, or other equivalent State or local rules'' (73 FR 78532, December 22, 2008). One commenter disagreed with the EPA's position, alleging that ''EPA's suggestion that it can waive compliance with the NSPS in this manner is contrary to the Clean Air Act.'' The commenter stated that the EPA's suggestion ''that existing state and local requirements render the federal requirements irrelevant only confirms that EPA's proposed flaring requirements do not reflect the *best* technological system of continuous emission reduction.'' 42 U.S.C. 7411(h)(1) (emphasis added). The commenter also stated that the CAA already provides a mechanism for implementation of alternative work practice standards in narrowly defined circumstances (42 U.S.C. 7411(h)(3)); an owner or operator may demonstrate to the Administrator that an alternative means of emissions limitation is equivalent to the federal standard on a case-by-case basis. Therefore, the commenter asserted, the CAA clearly states that ''EPA's authority to waive federal work practice standards is case specific.'' Finally, the commenter stated that the EPA did not explain how emissions reductions achieved through compliance with SCAQMD Rule 1118 are equivalent to 40 CFR part 60, subpart Ja. Further, the commenter asserted that the EPA neither identified other state or local rules that could be considered equivalent to subpart Ja, nor explained how the EPA would determine that a specific state or local rule is equivalent to subpart Ja. Therefore, the commenter asserted, it is impossible to fully assess the merit of the EPA's idea and provide meaningful comments.

Another commenter stated that ''most stringent'' is not one of the criteria that must be applied under the law to determine BSER. Therefore, the commenter asserted, it is not appropriate to argue that the EPA did not properly determine BSER simply because there exist state or local rules that are more stringent than federal requirements. The commenter also asserted that the EPA has full authority to establish alternative regulatory standards that are determined to be as stringent as or more stringent than BSER, and CAA section 111(h)(3) generally applies after the EPA has completed a national rulemaking and an owner or operator requests approval for a site-specific alternative at a later date. The commenter asserted that it is logical that, if an alternative method is identified during the rulemaking process, ''the law would allow EPA to establish a site-specific alternative [in the rule itself] (especially, as under [CAA section 111], where the alternative would have to be determined through notice and comment rulemaking).''

Other commenters recommended that refineries complying with SCAQMD Rule 1118 be deemed in compliance with 40 CFR part 60, subparts J and Ja. According to one commenter, SCAQMD Rule 1118 is ''in all respects equivalent to or more stringent than the corresponding requirements'' of subparts J and Ja. Commenters also recommended that refineries should be able to consider compliance with BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12 as compliance with the appropriate provisions of subpart Ja. One commenter provided a table comparing each of the six proposed flare management plan requirements in 40 CFR 60.103a(a) to the SCAQMD and BAAQMD regulations. The table identified sections of BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12 that are equivalent to the six subpart Ja flare management plan requirements. The commenter also noted that SCAQMD Rule 1118 is only equivalent to five of the proposed requirements; it does not require an owner or operator to identify procedures to reduce flaring in cases of fuel gas imbalance (although another commenter noted that SCAQMD Rule 1118 requires minimization of all flaring, including fuel gas imbalance). While most commenters focused on the equivalence of the flare management plan requirements of the SCAQMD and BAAQMD rules and the flare management plan requirements of subpart Ja, one commenter requested that the periodic sampling of BAAQMD Regulation 12, Rule 11 be considered equivalent to the continuous sulfur monitoring requirements of subpart Ja for emergency flares.

Response: First, we note that there seems to be some misunderstanding regarding how a determination that SCAQMD Rule 1118 or BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12 are equivalent to 40 CFR part 60, subpart Ja would actually be implemented in subpart Ja. The EPA will not ''waive'' the obligation to comply with subpart Ja if the source is complying with SCAQMD Rule 1118 or BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12. In other words, the EPA will not allow the owner or operator to ''choose'' to comply with SCAQMD Rule 1118 or BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12 instead of subpart Ja. Rather, the source must always demonstrate compliance with subpart Ja. If SCAQMD Rule 1118 or BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12 are determined to be equivalent to subpart Ja, then these requirements would be provided as an alternative within subpart Ja for the source to demonstrate that it is meeting the requirements of subpart Ja.

To assess the comments, we reviewed SCAQMD Rule 1118, BAAQMD Regulation 12, Rule 11, and BAAQMD Regulation 12, Rule 12 and compared these rules to the 40 CFR part 60, subpart Ja requirements we are finalizing here. We have included documentation of this review in Docket ID No. EPA–HQ–OAR–2007–0011 that shows the sections of each of those rules that we consider are equivalent to the subpart Ja requirements. We determined that SCAQMD Rule 1118 and BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12 will result in equivalent to or greater than the emissions reductions resulting from the subpart Ja flare management plan requirements. As a result of our analysis, we have amended subpart Ja, as described in the following paragraphs.

We determined that SCAQMD Rule 1118 is equivalent to the flare requirements and monitoring, recordkeeping and reporting provisions for determining compliance with the flare requirements in 40 CFR part 60, subpart Ja. We also determined that the combined provisions of BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 are equivalent to the flare requirements and monitoring, recordkeeping and reporting provisions for determining compliance with the flare requirements in subpart Ja. Therefore, we have added specific compliance options for flares that are located in the SCAQMD and are in compliance with SCAQMD Rule 1118, as well as for flares that are located in the BAAQMD and are in compliance with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12. Flares that are in compliance with these alternative compliance options are in compliance with the flare standards in subpart Ja. Specifically, 40 CFR 60.103a(g) specifies that flares that are located in the SCAQMD may elect to comply with SCAQMD Rule 1118 and flares that are located in the BAAQMD may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 to comply with the flare management plan requirements of 40 CFR 60.103a(a) and (b) and the root cause analysis and corrective action analysis requirements of 40 CFR 60.103a(c) through (e). In addition, 40 CFR 60.107a(h) indicates that flares that are located in the SCAQMD may elect to comply with the monitoring requirements of SCAQMD Rule 1118 and flares that are located in the BAAQMD may elect to comply with the combined monitoring requirements of both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 to comply with the monitoring requirements of 40 CFR 60.107a(e) and (f). The owner or operator must notify the Administrator, as specified in 40 CFR 60.103a(g), that the flare is in compliance with SCAQMD Rule 1118 or both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12. The owner or operator must also submit a copy of the existing flare management plan (if applicable), as specified in 40 CFR 60.103a(g).

We note that, as pointed out by commenters, an owner or operator maintains the ability under CAA section 111(h)(3) to submit a request to establish, on a case-by-case basis, that ''an alternative means of emission limitation will achieve a reduction in emissions * * * at least equivalent to the reduction in emissions'' achieved under the flare standards of 40 CFR part 60, subpart Ja. Pursuant to CAA section 111(h)(3), we also included specific provisions within 40 CFR 60.103a for owners or operators to submit a request for ''an alternative means of emission limitation'' that will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved under the final standards in subpart Ja.

Comment: Commenters suggested that the requirement to minimize discharges to the flare in 40 CFR 60.103a(a)(1) should specifically address routine discharges, and the EPA should limit the minimization requirements to actions that: (1) Are ''consistent with good engineering practices'' and (2) consider costs and other health and environmental impacts, as required by section 111 of the CAA.

Response: We agree that the language in proposed 40 CFR 60.103a(a)(1) appears to require an assessment of flare minimization irrespective of cost or other relevant considerations, as contained in CAA section 111, which was not our intent. We are clarifying, through this response, that cost, safety and emissions reductions may be considered when evaluating what actions should be taken to minimize discharges to a flare, but we disagree that the flare minimization assessment should be limited to ''routine discharges.'' We have revised the flare management plan requirements in 40 CFR 60.103a(a) to more fully describe the types of information that must be evaluated and included in the plan.

As noted in the summary of this rule (section III.C of this preamble), we are finalizing our proposed withdrawal of the 250,000 scfd 30-day rolling average flow limit for flares. This limitation does not adequately account for site-specific factors regarding flare gas Btu content, ability to offset natural gas purchase and other considerations. We find that these factors need to be addressed in a site-specific basis and are more appropriately addressed through the flare management plan. In the absence of the specific flow limitation, we have included additional requirements in the flare management plan to prompt a thorough review of the flare system so that, as an example, flare gas recovery systems are installed and used where these systems are warranted. We have also revised the flare minimization requirements to require the flare management plans to be submitted to the Administrator (40 CFR 60.103a(b)).

As part of the development of the flare management plan, refinery owners and operators can provide rationale and supporting evidence regarding the flare reduction options considered, the costs of each option, the quantity of flare gas that would be recovered or prevented by the option, the Btu content of the flare gas and the ability or inability of the reduction option to offset natural gas purchases. The plan will also include the rationale for the selected reduction option, including consideration of safety concerns. The owner or operator must comply with the plan, as submitted to the Administrator. Major revisions to the plan, such as the addition of an alternative baseline (see next comment for further detail on baselines), must also be submitted to the Administrator.

In summary, although we did not incorporate the commenter's suggested language for limiting the scope of the minimization requirements to actions that are ''consistent with good engineering practices'' and that ''consider costs and other health and environmental impacts,'' we acknowledge that these are valid considerations in the selection of the minimization alternatives available for a given affected flare. We find that the process of developing and submitting the flare management plan will ensure that these factors are considered consistent with CAA section 111 and that the requirement to minimize discharges to the flare is implemented consistently across all affected sources.

Comment: Commenters asserted that the flare flow root cause analysis threshold of 500,000 scf in any 24-hour period is arbitrary and cannot be fairly applied to all flares at all refineries. One commenter cited an ultracracker flare that routinely cycles from 5 million to 25 million scfd as an example of a flare for which the threshold of 500,000 scf in any 24-hour period would result in constant and meaningless root cause analyses. The commenters suggested removing the numerical threshold and limiting root cause analysis to upsets and malfunctions as initially promulgated in June 2008 (because root cause analysis is generally only effective for reducing non-routine flows) or using a site- or flare-specific threshold instead. Even if the numerical threshold is revised, the commenters suggested that a number of streams be excluded from the calculation of flow, such as hydrogen and nitrogen, purge and sweep gas, natural gas added to increase the Btu content of the flare gas and gases regulated by other rules to avoid performing multiple root cause analyses for routine events. One commenter suggested that owners or operators should be able to use one root cause analysis report for an event that occurs routinely (as allowed in the consent decrees).

Response: We proposed the flare flow root cause analysis threshold of 500,000 scf in any 24-hour period because we projected that flare gas recovery would be a cost effective emission reduction technique for flares with fuel gas flows that routinely exceed 500,000 scfd, although we acknowledge that the threshold at which flare gas recovery becomes cost effective is strongly (inversely) correlated to the average Btu content of the flare gas (*i.e.,* a relatively small reduction in the Btu content of the gas makes the recovery system significantly less cost effective). Although we did not specifically exclude sweep or purge gas from the flow, we expected that the flow rates of sweep or purge gas (*i.e.,* gases needed to ensure the readiness of the flare and the safety of the flare gas system) would be negligible when compared to the root cause analysis threshold of 500,000 scf in any 24-hour period. In fact, in our original analysis of the appropriate flow rate root cause analysis threshold (Docket Item No. EPA–HQ–OAR–2007–0011–0246), we essentially assumed that the sweep and purge gas flow rates were zero, and we estimated costs and emissions reductions of the 500,000 scf in any 24-hour period threshold, based on recovering that amount of gas or eliminating recurring events of that size (rather than 500,000 scf minus the sweep or purge gas flow).

However, while we do not believe that 5 million scfd[10] is a reasonable base flow for a flare, we do acknowledge that the size of the flare, as well as the flare header system, will greatly impact the required flow needed to maintain the readiness of the flare. Although we can derive suitable flare flow thresholds for average conditions, these thresholds are not necessarily reasonable when applied to all flows, and we did not intend for on-going root cause analyses to be conducted on account of sweep or purge gas.

Therefore, rather than specifying a one-size-fits-all threshold, the final rule requires facilities to develop their own base flare flow rates as part of their flare management plan. A flow-based root cause analysis is triggered if flows measured by the flow monitor exceed 500,000 scf greater than the base flare flow rate in any 24-hour period. Evaluating the flow rate threshold above a baseline better reflects our original analysis of the impacts of flow-based root cause analyses when the sweep or purge gas flow rates are not negligible. We also note that 40 CFR 60.103a(d) allows a single root cause analysis to be conducted for any single continuous discharge that causes the flare to exceed either the root cause analysis threshold for SO_2 or flow for two or more consecutive 24-hour periods.

The final rule does not limit root cause analyses to upsets and malfunctions of refinery process units and ancillary equipment connected to the flare, nor does it explicitly allow owners or operators to use one root cause analysis report for an event that occurs routinely. When we decided to eliminate the numerical limit on flare flow rate, we specifically increased the scope of the flare flow root cause analysis to cover more than just upsets and malfunctions. We also decided not to explicitly allow owners or operators to use one root cause analysis report for an event that occurs routinely as a means to discourage routine flaring of recoverable gas. However, we recognize that there may be recurring discharges to the flare that are not recoverable for various reasons. Therefore, the final rule does allow for several base cases, which could include recurring maintenance; this provision will avoid multiple root cause analyses for a recurring event. As described above, the flare management plan (as well as significant revisions to the plan to include alternative baselines) must be submitted to the Administrator. The Administrator or delegated authority (*e.g.,* the state) may review the plan, although formal approval of the plan is not required. Not specifying a formal approval process is intended to minimize the burden associated with reviewing flare management plans. Rather, the rule specifies elements of the plan that need to be addressed in order for the plan to be considered adequate and provides an opportunity for a delegated authority to find the plan not adequate if they choose to do so.

We expect that a final flare management plan in compliance with 40 CFR part 60, subpart Ja will possess the following characteristics: (1) Completeness (all gas streams are considered, all required elements are included and all appropriate flare reduction measures are evaluated); (2) accuracy (the emission reductions and cost estimates for the different options are accurate); and (3) reasonableness (the selection of reduction options is correct and the baseline flow value is reasonable). If the Administrator identifies deficiencies in the plan (*e.g.,* the plan does not contain all the required elements, alternative flare reduction options were not evaluated or selected when reasonable, the baseline or alternative baseline flow rates are considered unreasonable), the Administrator will notify the owner or operator of the apparent deficiencies. The owner or operator must either revise the plan to address the deficiencies or provide additional information to document the reasonableness of the plan.

Comment: Commenters requested alternative monitoring options or an exemption from continuous flow monitoring for: (1) Flares designed to handle less than 500,000 scfd of gas; (2) pilot gas; (3) flares with flare gas recovery systems; (4) emergency flares; and (5) secondary flares. The commenters asserted that flow meters are costly and engineering calculations, which are currently used, are sufficient to evaluate when the flow to a flare exceeds 500,000 scf in any 24-hour period. One commenter stated that, for flares with flare gas recovery systems, the pressure drop across the flare seal drum can be used to calculate flow rate.

Response: In the final rule, flow monitoring is used to determine whether a root cause analysis is required rather than to ensure compliance with a specific flow limit. We have reviewed the commenters' suggestions and agree that, in certain specific cases, monitoring is not necessary and should not be required. However, as a general rule, we believe flow monitors are needed, not only to provide a verifiable measure of exceedances of the flow root cause analysis threshold, but also exceedances of the root cause analysis threshold of 500 lb SO_2 in any 24-hour period. In addition, when we evaluated local rules,

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[10] Regarding commenter's cited ultracracker flare example, it is difficult to believe that sweep gas alone accounts for 5 million scfd of flare gas flow. Additionally, a compositional analysis of the base flare gas from the normal flow, based on data provided from a DIAL study of this refinery, suggests that the base flare gas is of sufficient quality to recover. It also appears, based on the data provided by the commenter, that the hydrogen stream recycle compressor was off-line approximately half the year. For such huge gas flows, considering the cost of purchasing or producing additional hydrogen and the emissions associated with that process, it is reasonable to expect that the facility would have a back-up compressor if the primary compressor is unreliable.

such as the initial BAAQMD rule for flare monitoring, we saw that the measured flare flow rates were several times greater than previously projected by the facilities.

Consequently, we find great value in the flow monitoring requirements for flares. These monitoring requirements will greatly improve the accuracy of emissions estimates from these flares. The resulting improved accuracy of flare emissions estimates will also lead to better decision-making as we conduct future reviews of rules applicable to petroleum refineries. We did consider each of the commenters' suggested exemptions in light of this fact; our specific considerations follow.

We did not specifically consider that some flares would not be capable of exceeding the flow root cause analysis threshold (*i.e.,* designed to handle less than 500,000 scfd of gas). However, these small flares could still exceed the root cause analysis threshold of 500 lb SO_2 in any 24-hour period. As such, we did not provide an exemption from the monitoring requirements for these small flares.

We agree that the monitoring of pilot gas flow is not needed. In the final rule, a root cause analysis is required if the gas flow to the flare exceeds 500,000 scf above the baseline in any 24-hour period. The flow of pilot gas is considered to be part of the baseline flow and is assumed to be constant. As such, monitoring of pilot gas would not be necessary to determine whether a flare has exceeded 500,000 scf above the baseline in any 24-hour period. In practice, the actual baseline flow set for the flare may or may not expressly include the pilot gas flow rate. Generally, the configuration of the flare header is such that the flare flow monitor would not measure pilot gas flow. In this case, the baseline flow determined for the flare would not expressly include the pilot gas flow rate. If the flare flow monitor is configured in such a way that it does measure pilot gas, then pilot gas would be considered part of the baseline conditions for that flare.

We agree with commenters that flares with flare gas recovery systems do have unique conditions and these warrant alternative monitoring options. Additionally, we recognize that the monitoring requirements may be burdensome for flares that are truly ''emergency only'' (*i.e.,* flares that flare gas rarely, if at all, during a typical year) or for secondary flares in a cascaded flare system. These flares are expected to have a water seal that prevents flare use during normal operations and ensures that the pressure upstream of the water seal (expressed in inches of water) does not exceed the water seal height during normal operations (hereafter referred to as ''properly maintain a water seal''). We find that, for these select types of flares, water seal monitoring as an alternative to the flow (and sulfur) monitoring provisions is appropriate.

For flares with a flare gas recovery system and other emergency or secondary flares that properly maintain a water seal, the final rule states that an owner or operator may elect to monitor the pressure in the gas header just before the water seal and monitor the water seal liquid height to verify that the flare header pressure is less than the water seal, which is an indication that no flow of gas occurs. If the flare header pressure exceeds the water seal liquid level, a root cause analysis is triggered unless the pressure exceedance is attributable to staging of compressors. This alternative reduces the costs associated with installing sulfur and flow monitoring systems for flares that rarely receive fuel gas. Engineering calculations can be used to estimate the emissions during the event, but not for determining whether or not a root cause analysis is required.

To ensure that this option is only used for flares that are truly emergency flares and not for flares that are used for routine discharges, the final rule contains a limit on the number of pressure exceedances requiring root cause analyses that can occur in one year. Following the fifth reportable pressure exceedance in any consecutive 365 days, the owner or operator must comply with the sulfur and flow monitoring requirements of 40 CFR 60.107a(e) and (f). Based on a review of available flaring data, we expect that gas may be sent to an emergency flare three to four times per year, on average. Consistent with this information, we are providing in these final amendments that an ''emergency flare'' may receive up to four releases to the flare in any consecutive 365-day period to account for year-to-year variability. However, a flare receiving more than four discharges in a consecutive 365-day period can no longer be considered an ''emergency flare'' and must install the required sulfur and flow monitors.

Comment: Commenters requested an exemption from continuous sulfur monitoring or alternative monitoring options for flares handling only gases inherently low in sulfur content, emergency flares, flares with properly designed flare gas recovery systems and secondary flares. For flares handling gases low in sulfur, the commenters noted that continuous monitoring is unnecessary and certain fuel gas streams are already exempted from monitoring if they are combusted in a fuel gas combustion device. For flares that handle only gases exempt from the H_2S concentration requirements and flares with properly designed flare gas recovery systems, commenters stated that engineering calculations are sufficient to determine if the SO_2 root cause analysis threshold of 500 lb in any 24-hour period is exceeded. One commenter requested that the EPA allow owners or operators to submit and use an alternative monitoring plan to demonstrate that the flare gas recovery system is operating within its capacity and to calculate SO_2 emissions from engineering calculations and flare gas sampling. For secondary flares, one commenter noted that the continuous sulfur monitor on the primary flare could be used to determine the sulfur content of the gas being flared from the secondary flare.

One commenter requested that the EPA allow the use of engineering calculations to determine the sulfur-to-H_2S ratio because sampling can be difficult for emergency flares. One commenter noted that the EPA should allow the use of an existing continuous monitoring system if the gas sent to the flare is already monitored elsewhere. As examples, the commenter cited fuel gas and pilot gas already monitored within the fuel gas system.

For flares that rarely see flow, commenters particularly cited difficulties with performance tests. Commenters noted that, to meet the sulfur monitor performance test requirements, an owner or operator may have to intentionally flare gas that may not meet the H_2S concentration limits. One commenter also stated that performing the required relative accuracy test audit (RATA) could cause the flare to exceed the root cause analysis threshold. The commenter recommended revising the performance test requirements for flares with flare gas recovery to require only a cylinder gas audit.

Response: We have amended the final rule so that gases that are exempt from H_2S monitoring due to low sulfur content are also exempt from sulfur monitoring requirements for flares. For low-sulfur gases, the flare root cause analysis will always be triggered by an exceedance of the flow rate threshold well before the SO_2 threshold is exceeded, so no sulfur monitoring is required. However, this exemption can only be used for flares that are configured to receive only fuel gas streams that are inherently low in sulfur content, as described in 40 CFR

60.107a(a)(3), such as flares used for pressure relief of propane or butane product spheres (fuel gas streams meeting commercial grade product specifications for sulfur content of 30 ppmv or less) or flares used to combust fuel gas streams produced in process units that are intolerant to sulfur contamination (*e.g.,* hydrogen plant, catalytic reforming unit, isomerization unit or hydrogen fluoride alkylation unit). We already clarified that flare pilot gas is not required to be monitored. Also, 40 CFR part 60, subpart Ja already allows for H_2S monitoring at a central location, such as the fuel mix drum, for all fuel gas combustion devices (and we are finalizing amendments to ensure it is clear that H_2S monitoring at a central location is allowed for flares as well). Thus, we agree that if a flare only burns natural gas, fuel gas monitored elsewhere or fuel gas streams that are inherently low in sulfur content (as defined in 40 CFR 60.107a(a)(3)), then no H_2S monitor is needed.

The remaining issue is whether or not sulfur monitoring is necessary for ''emergency only'' flares. (An emergency flare is defined as a flare that combusts gas exclusively released as a result of malfunctions (and not startup, shutdown, routine operations or any other cause) on four or fewer occasions in a rolling 365-day period. For purposes of the rule, a flare cannot be categorized as an *emergency flare* unless it maintains a water seal.) We acknowledge that there are difficulties and costs with installing monitors on flares that rarely operate. However, we are concerned about how the owner or operator will detect emissions above 500 lb SO_2 in any 24-hour period during an upset or malfunction of a refinery process unit or ancillary equipment connected to the flare. Commenters appear to have conflicting opinions regarding the ability to sample the flare gas to determine the sulfur content (or total sulfur-to-H_2S ratio) during a flaring event. If samples could be taken during the flaring events, then that would be a potential option. However, during a process upset or malfunction, focus should be on alleviating the problem rather than taking a special sample. Also, given the duration of some of these events, it appears unlikely that representative samples can be manually collected.

Taking the difficulties discussed above into account, we have developed an alternative monitoring option for emergency flares. As noted in the previous response, emergency flares are expected to properly maintain a water seal. We provide pressure and water seal liquid level monitoring, as previously described as an alternative to the sulfur and flow monitors. As described in more detail above, any fuel gas pressure exceeding the water seal liquid level triggers a root cause analysis and there is a limit to the number of exceedances in one year. Under this option, a root cause analysis is triggered, based on the monitored pressure and water seal height, so accurate measurements of flow rate and sulfur concentrations are less critical than for flares that must evaluate these parameters to determine if a root cause analysis is needed. Consequently, for these flares, engineering calculations can be used to estimate the reported emissions during the flaring event, but the root cause analysis must be performed regardless of the magnitude of these engineering estimates. Using this alternative monitoring option, emergency flares are not required to install continuous sulfur monitoring systems. Flares that do not meet the conditions of an emergency flare are required to install continuous sulfur monitoring systems and cannot elect this alternative monitoring option.

We also agree that flaring solely for the purpose of a RATA or other performance test is not desirable. The ''cylinder gas audit'' procedures requested by the commenter are described as alternative relative accuracy procedures in section 16.0 of Performance Specification 2 (referenced from Performance Specification 5). We reviewed the alternative relative accuracy procedures and considered how they may apply to flares, and we have determined that the alternative relative accuracy procedures are appropriate for flares. We expect that, for most affected flares, the variability in flow (including no flow conditions) and sulfur content of the gases discharged to the flare create significant barriers to the normally required relative accuracy assessments, particularly if those assessments need to be made over a range of sulfur concentrations potentially seen by the monitor. Therefore, we are amending 40 CFR 60.107a(e)(1)(ii) and 40 CFR 60.107a(e)(2)(ii) to specify that the owner or operator of a flare may elect to use the alternative relative accuracy procedures in section 16.0 of Performance Specification 2 of Appendix B to part 60. As required by 40 CFR 60.108a(b), the owner or operator shall notify the Administrator of their intent to use the alternative relative accuracy procedures.

Comment: One commenter requested that the EPA clarify whether the additionally proposed sulfur monitoring options for flares are for total reduced sulfur or total sulfur. The commenter noted that measuring total sulfur is the simplest and most inclusive measurement of SO_2 emissions and it is the method included in SCAQMD Rule 1118. The commenter also requested that methods for measuring total sulfur in gaseous fuels be included as acceptable options to perform the relative accuracy evaluations of the CEMS.

One commenter requested that provisions be made in 40 CFR 60.107a(e)(2) to develop a total sulfur-to-H_2S (or total reduced sulfur-to-H_2S) ratio so that the total sulfur monitor can be used for both the root cause analysis requirements and for compliance with the requirement to limit short-term H_2S concentration in fuel gas sent to a flare to 162 ppmv without the need for a duplicative continuous H_2S monitor. Another commenter supported the addition of alternative monitoring methods for the sulfur content of flare gas, but noted that since the composition of flare gas is highly variable, the alternative methods must meet continuous monitoring requirements.

Response: We have clarified and consolidated the monitoring requirements to allow total reduced sulfur monitoring for flares. For the purposes of evaluating the SO_2 root cause analysis threshold, total sulfur monitoring provides the most accurate assessment. However, in most cases, the vast majority of sulfur contained in gases discharged to the flare is expected to be in the form of total reduced sulfur compounds, which include carbon disulfide, carbonyl sulfide and H_2S. Our test method for measuring total reduced sulfur includes the use of EPA Method 15A as a reference method, and because EPA Method 15A measures total sulfur, the total reduced sulfur monitoring requirement is equivalent to a total sulfur monitoring method.

As discussed previously, we are relying on the suite of flare requirements we are promulgating to limit SO_2 emissions at the flare. These include optimizing management of the fuel gas by limiting the short-term concentration of H_2S to 162 ppmv during normal operating conditions. We expected most refineries would already have the H_2S monitor and did not consider the use of a total sulfur monitor for use in complying with the short-term 162 ppmv H_2S concentration in the fuel gas. As the H_2S concentration will always be less than the total reduced sulfur concentration, it is acceptable to use the total reduced sulfur monitor to verify that the fuel gas does not exceed the short-term H_2S concentration of 162 ppmv. Therefore, we have provided for the use of total reduced sulfur monitors, provided the monitor can also meet the 300 ppmv span requirement.

However, we have not provided a correction factor to scale down the total reduced sulfur concentration to H_2S. The owner or operator using this method must essentially be able to demonstrate they can achieve a 162 ppmv total reduced sulfur concentration in the fuel gas. The concentration ratio was provided for the purposes of the root cause analysis because of the costs of adding a total sulfur monitoring system when a dual range H_2S monitor was already in-place, as well as the expected accuracy needed for the system to assess the SO_2 root cause analysis threshold. As few cases would exist where the flaring event would be right at the SO_2 root cause analysis threshold of 500 lb in any 24-hour period, inaccuracies associated with the average total sulfur-to-H_2S ratio were not expected to be significant.

On the other hand, the short-term 162 ppmv H_2S concentration in the fuel gas must be continuously maintained, and the total sulfur-to-H_2S ratio at these low concentrations is expected to be highly variable, depending on the efficiency of the amine scrubber systems. As the amine scrubber systems, according to previous industry comments, are not effective for reduced sulfur compounds other than H_2S, the non-H_2S reduced sulfur concentration is expected to be fairly constant, with most of the fluctuations in total sulfur content being attributable to fluctuations in H_2S concentrations. Consequently, we have determined that the inaccuracies of the ratio approach are not acceptable for continuously demonstrating that the short-term concentration in the fuel gas does not exceed 162 ppmv H_2S. Therefore, owners or operators of affected flares may use the direct output of a total reduced sulfur monitor to assess compliance with the short-term 162 ppmv H_2S concentration in the fuel gas, or they must install a continuous H_2S monitor.

Comment: One commenter supported the proposed amendment revising the span value for fuel gas H_2S analyzers to match the span requirements in 40 CFR part 60, subpart J, stating this will save time and money. However, the commenter stated that the span value for the flare H_2S monitoring option is too restrictive and suggested that requirements in Appendix F to part 60 provide sufficient quality assurance/quality control (QA/QC) without the need for the rule to specify the span range. The commenter also requested clarification of the sulfur monitor span for flares, suggesting that it should be based on the H_2S concentration limits and that engineering calculations can be used to assess exceedances of the SO_2 root cause analysis threshold of 500 lb in any 24-hour period.

Response: The H_2S span value is at 300 ppmv to verify compliance with the H_2S concentration requirement for the fuel gas; the span of the total sulfur monitor needs to be much greater than that to be able to quantify the sulfur content in streams containing several percent sulfur. For units that use the H_2S analyzers both to assess compliance with the short-term 162 ppmv H_2S concentration requirement for the fuel gas and to assess exceedances of the SO_2 root cause analysis threshold of 500 lb in any 24-hour period, a dual range monitor will be necessary. For the purposes of the SO_2 root cause analysis threshold of 500 lb in any 24-hour period, we intended that the monitor be capable of accurately determining the sulfur concentration for the range of concentrations expected to be seen at the flare. We are particularly interested in quantifying the concentrations of high sulfur-containing streams as these would be the streams most likely to trigger a root-cause analysis at low flows. We proposed that the span for the flare sulfur monitor be selected from a range of 1 to 5 percent. We agree with the commenter that this may be too restrictive, and we have revised the span requirements to be determined, based on the maximum sulfur content of gas that can be discharged to the flare (*e.g.,* roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but no less than 5,000 ppmv. A single dual range monitor may be used to comply with the short-term 162 ppmv H_2S concentration requirement for the fuel gas and the SO_2 root cause analysis threshold monitoring requirement provided the applicable span specifications are met. In reviewing the span specifications, we noted that span requirements were inadvertently omitted from the total reduced sulfur compound monitoring alternative. The purpose of these monitors is identical to the H_2S monitoring alternative, and the same span considerations apply for these monitors.

We disagree that the QA/QC procedures in Appendix F to part 60 are sufficient without specifying the span values. Procedure 1 of Appendix F to part 60 defines ‘‘span value’’ as: ‘‘The upper limit of a gas concentration measurement range that is specified for affected source categories in the applicable subpart of the regulation.’’ The concentrations used for calibration are based on the span value. Several of the QA/QC procedures in Appendix F are undefined if the span value is not defined in the rule.

Comment: Commenters stated that time is needed to install continuous monitors and to make other necessary changes (such as installing a flare gas recovery system or additional amine treatment) to comply with all the flare requirements (*e.g.,* limiting short-term H_2S concentration to 162 ppmv, long-term 60 ppmv H_2S fuel gas concentration limit, flare management plan, root cause analysis and continuous monitoring), especially considering how quickly a flare may become a modified affected source. While most commenters focused on the amount of time needed to install equipment to comply with the long-term 60 ppmv H_2S fuel gas concentration limit, other commenters asserted that additional time for activities, such as planning and re-piping, would be needed to meet the standards. Commenters requested differing amounts of additional time generally ranging from 3 to 5 years. Commenters noted that the additional time would allow owners and operators to schedule any process unit shutdowns needed to install new equipment or monitors during a turnaround. One commenter recommended that the extra time to begin root cause analyses provided to refiners committing to install flare gas recovery systems should also be provided to refiners committing to expand an existing flare gas recovery system. Commenters also noted that experience implementing SCAQMD Rule 1118 suggests that there will be difficulty obtaining and installing continuous monitors in less than 3 years due to the availability of monitor manufacturers and the need to stage the installation of monitors at refineries with multiple affected flares. One commenter requested that the EPA consider a compliance schedule in 40 CFR part 60, subpart Ja that is consistent with compliance schedules in consent decrees. Commenters objected to phasing out the additional time after the rule has been in place for 5 years.

One commenter requested clarification regarding the trigger date from which the additional time to comply with the flare provisions (*e.g.,* 2 years when installing a flare gas recovery system) begins. The commenter questioned whether the trigger date is when construction starts, at startup or when the stay is removed (or whichever is later). Another commenter agreed that the EPA should set the compliance time based on the initial startup of the modification. The commenter noted that the EPA should follow the 40 CFR part 60 General Provisions for performance test timing and the 40 CFR part 63 General Provisions for compliance timing.

Response: As we are no longer applying the long-term 60 ppmv H_2S fuel gas concentration limit to flares, the comments related to the amount of time needed to comply with a long-term 60 ppmv H_2S fuel gas concentration limit are moot. We do, however, recognize that a flare modification can occur much more quickly than modifications of traditional process-related emission sources. Therefore, we evaluated the comments regarding the amount of time needed to meet the various requirements for flares while keeping the 40 CFR part 60, subpart Ja flare modification provision in mind. We discuss each requirement and the time for demonstrating compliance with that requirement in the following paragraphs.

We find it appropriate to require modified flares that already have adequate treatment and monitoring equipment in place to achieve a short-term H_2S concentration of 162 ppmv (resulting from compliance with 40 CFR part 60, subpart J) to continue to meet that concentration upon startup of the affected flare or the effective date of this final rule, whichever is later. However, some flares are not affected facilities subject to 40 CFR part 60, subpart J, and others are complying with subpart J requirements as specified in consent decrees or have received alternative monitoring plans by which to demonstrate compliance with the short-term H_2S concentration limit. In these cases, we find it appropriate to allow more time to comply with the short-term H_2S concentration limit and/or the associated monitoring requirements because additional amine treatment and/or monitoring systems will be required to comply with the rule.

Therefore, the final rule requires all modified flares that are newly subject to 40 CFR part 60, subpart Ja (but were not previously subject to 40 CFR part 60, subpart J) to comply with the short-term H_2S concentration limit and applicable monitoring requirements no later than 3 years after the effective date of this final rule or upon startup of the affected flare, whichever is later. Modified flares that have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree but shall comply with the short-term H_2S concentration limit and applicable monitoring requirements no later than 3 years after the effective date of this final rule. Modified flares that are already subject to the 162 ppmv short-term H_2S concentration limit under subpart J must meet the short-term H_2S concentration limit under subpart Ja upon startup of the affected flare or the effective date of this final rule, whichever is later. Finally, modified flares that are already subject to the short-term H_2S concentration limit but that have an approved monitoring alternative under subpart J and do not have the monitoring equipment in-place that is required under subpart Ja shall be given up to 3 years from the effective date of this final rule to install the monitors required by subpart Ja (or to obtain an approved monitoring alternative under subpart Ja).

As we noted in the preamble to the proposed amendments, many of the connections that would trigger applicability to 40 CFR part 60, subpart Ja are critical to the safe and efficient operation of the refinery. These connections can, and often must, be installed quickly. At the same time, nearly all refineries will need time for planning, designing, purchasing and installing (including any necessary re-piping) sulfur and flow monitors that are newly required by subpart Ja. Some refineries will elect to add flare gas recovery and/or sulfur treatment equipment to minimize their emissions as part of the evaluations conducted, as required by the new flare management plan requirements, and time will be needed for planning, designing, purchasing and installing these components as well. Given that many flares will become modified affected sources relatively quickly, owners and operators will be competing with one another for the services and products of a finite number of vendors who provide the necessary monitors and other equipment. Several commenters specifically noted availability of monitors as an issue when complying with SCAQMD Rule 1118. As such, we find that immediate compliance with the requirements for flares, such as the planning, designing, purchasing and installation of (including any necessary re-piping) sulfur and flow monitors, may be difficult for operators to meet, especially in situations where quick connections to the flare are made. A phased compliance schedule allows for the operators to comply with some requirements associated with flares, such as continuing to achieve a short-term H_2S concentration of 162 ppmv, if the flares are already subject to 40 CFR part 60, subpart J and have adequate monitoring in place to comply with this final rule, while allowing time to install treatment and processing equipment and monitoring equipment to comply with the standards where necessary.

A phased compliance schedule will also allow owners and operators to minimize process interruption by coordinating the installation of monitoring equipment with process shutdowns or turnarounds. In addition to providing operating flexibility to the refinery, we are taking into consideration the fact that a process shutdown and subsequent startup can generate significant emissions, even if the refinery is taking care to minimize those emissions. We consider a phased compliance schedule that allows owners and operators to avoid startups and shutdowns that are not necessary to maintain the equipment and process to be environmentally beneficial overall and the best system of emissions reduction for a quickly modified flare. Considering the time needed to complete engineering specifications, order and install the required monitoring equipment, and considering the need to coordinate this installation with process unit shutdown or turnarounds, we determined that completion of these activities within 3 years is consistent with the best system of emissions reductions for quickly modified flares.

We note, however, that this phased compliance schedule for the flare requirements in 40 CFR part 60, subpart Ja is intended for those situations when a flare modification occurs quickly and the owner or operator does not have significant planning opportunities to install the required monitors or implement the selected flare minimization options without significant process interruptions. For a future large project on a schedule that includes time for planning, designing, purchasing and installing equipment and monitors, we expect that the owner and operator will have time to assess whether or not the refinery flares will become affected sources through modification. If a project will result in the modification of a flare, we expect that the owner or operator will then plan how to meet the standards in subpart Ja as part of the project itself, including the installation of the monitoring systems and the development of a flare management plan. Because of the ability to plan ahead, flares that are modified as part of a large project will not have all of the difficulties meeting the subpart Ja flare requirements upon completion of the modification as those flares that are modified quickly. Therefore, we find that compliance with the flare requirements upon startup of the modified flare is appropriate and consistent with the best system of emissions reduction for large projects resulting in a modification of a flare. Thus, we determined that the appropriate time period for compliance with the flare standards is either: (1) 3 years from the effective date of these amendments or (2) upon startup of the modified flare, whichever is later.[11] In this manner, flares that become subject to subpart Ja quickly, based on a small safety-related connection (or have already become subject to subpart Ja based on a modification prior to the effective date of these amendments), will have up to 3 years from the effective date of these amendments to comply fully with the flare standards, but flares that are modified as the result of a significant project, such as the installation of a new process unit that will be tied into an existing flare, will effectively be required to comply with the flare standards at the startup of the new process unit.

Therefore, for the reasons described above, we are providing flares that become affected facilities subject to 40 CFR part 60, subpart Ja through modification with a phased compliance schedule for the flare standards, as described in this paragraph. The final rule requires owners and operators of modified flares to meet the short-term 162 ppmv H_2S concentration requirement by the effective date of these amendments or upon startup of the affected flare (whichever is later) only if they are already subject to the short-term 162 ppmv H_2S concentration limit in 40 CFR part 60, subpart J. Modified flares that were not affected flares under subpart J prior to being modified facilities under subpart Ja must comply with the short-term 162 ppmv H_2S concentration requirement within 3 years of the effective date of these amendments or upon startup of the modified flare, whichever is later. Owners and operators of modified flares that are have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree, but must meet the short-term 162 ppmv H_2S concentration limit no later than 3 years after the effective date of this final rule. Owners and operators of modified flares that are already subject to subpart J and that have an approved monitoring alternative and are unable to meet the applicable subpart Ja monitoring requirements for the short-term H_2S concentration limit must meet the short-term H_2S concentration requirement upon startup of the affected flare or the effective date of this final rule, whichever is later, but shall be given up to 3 years from the effective date of this final rule to install the monitors required by subpart Ja. In this interim period, owners and operators of these modified flares shall demonstrate compliance with the short-term H_2S concentration limit using the monitoring alternative approved under subpart J.

Additionally, we are requiring owners and operators of modified flares to complete and implement the flare management plan under 40 CFR 60.103a(a) by 3 years from the effective date of these amendments or upon startup of the modified flare, whichever is later. We are requiring owners and operators of modified flares to begin conducting root cause and corrective action analyses under 40 CFR 60.103a(c) and (d) no later than 3 years from the effective date of these amendments or the date of the startup of the modified flare, whichever is later, so that the facility can complete the flare management plan and establish baseline flow rates prior to performing the root cause and corrective action analyses. We are also requiring owners and operators of modified flares to install and begin operating the monitors necessary to demonstrate compliance with these provisions, as required under 40 CFR 60.107a(e) through (g) within 3 years from the effective date of these amendments or by the startup date of the modified flare, whichever is later, when the monitors are not already in place. Compliance with the phased compliance schedule constitutes compliance with the flare standards as of the effective date.

We note that the final rule does not provide a phased compliance schedule for new and reconstructed flares. The final rule requires owners and operators of new and reconstructed flares to meet all the flare requirements, including the short-term 162 ppmv H_2S concentration requirement, upon the effective date of the requirements or upon startup of the affected flare, whichever is later.

C. Other Comments

Comment: Several commenters objected to the change to the definition of ‘‘refinery process unit.’’ The commenters objected to the proposed amendments to include coke gasification, loading and wastewater treatment, stating the change makes the term more expansive. The commenters stated that the EPA did not evaluate the impacts or explain the consequences of the revised definition. One commenter stated that product loading is generally considered part of the refinery process unit to which it is associated and that wastewater treatment is a utility. Another commenter suggested that the definition specify SIC 2911 (as in Refinery MACT 1).

Response: The original definition of ‘‘refinery process unit’’ in 40 CFR part 60, subpart J and the definition of ‘‘refinery process unit’’ promulgated in 40 CFR part 60, subpart Ja in June 2008 read as follows: ‘‘Refinery process unit means any segment of the petroleum refinery in which a specific processing operation is conducted.’’ Thus, to be considered a refinery process unit, only two criteria are needed: (1) The unit must be located at a petroleum refinery; and (2) the unit must be used to conduct ‘‘a specific processing operation.’’ The definition does not directly limit the scope of ‘‘processing operations.’’ That is, the definition of refinery process unit does not limit process operations to distillation, re-distillation, cracking or reforming, and it is not limited to only those processes used to produce gasoline, kerosene, fuel oils, etc. In the proposed amendment to this definition, we listed ‘‘operations’’ that we construed as conducting a ‘‘specific processing operation’’ when these operations are located at a petroleum refinery. Consequently, we considered the proposed inclusion of examples of refinery process units to be a clarification of the existing definition rather than an expansion of the original definition.

We reviewed the impact of the proposed revision of this definition on 40 CFR part 60, subpart Ja, as well as its historic use in 40 CFR part 60, subpart J. The term ‘‘refinery process unit’’ is used primarily in the definitions of certain affected facilities, ‘‘process gas’’ and ‘‘process upset gas’’ in subparts J and Ja. The term is also used in the flare provisions in subpart Ja. With respect to the definitional terms, there can be no issue with including the designation of ‘‘refinery process unit’’ within the definitions for specific process units. ‘‘Process gas’’ is not used at all in either rule, although it was revised between proposal and promulgation of subpart J. In response to a comment that the definition of ‘‘process gas’’ ‘‘should have included the non-hydrocarbon gases produced by various process units in a refinery,’’ the EPA responded: ‘‘The definition has been revised to include all gases produced by process units in a refinery except fuel gas and process upset gas.’’ (See page 127 of *Background*

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[11] For the purposes of this subpart, startup of the modified flare occurs when any of the activities in 40 CFR 60.100a(c)(1) or (2) is completed (*e.g.,* when a new connection is made to a flare such that flow from a refinery process unit or ancillary equipment can flow to the flare via that new connection).

Information for New Source Performance Standards, Volume 3, Promulgated Standards (BID Vol. 3), EPA 450/2–74–003 (Feb. 1974), Docket Item No. EPA–HQ–OAR–2007–0011–0082). The definition had actually been revised to include ''any gas generated by a petroleum refinery process unit.'' The response in BID Vol. 3 suggests that the EPA considered ''refinery process units'' and ''process units in a refinery'' to have the same meaning, and there is no mention of limiting what is considered to be a ''refinery process unit'' or a ''process units in a refinery.''

''Process upset gas'' is used only to provide an exemption to the H_2S concentration limit for process upset gas sent to a flare. See 40 CFR 60.104(a)(1), 60.103a(h). Therefore, a narrow definition of ''refinery process unit'' would only limit those gases sent to a flare that would qualify as ''process upset gas.'' For example, if a coke gasifier is not a refinery process unit, then gases generated during the startup, shutdown or malfunction of a coke gasifier located at the refinery would not be ''process upset gas'' and would be required to comply with the requirement to limit short-term H_2S concentration in fuel gas to 162 ppmv if sent to a flare. We find that the historical application of the ''process upset gas'' exclusion has considered a broad definition of what constitutes a ''refinery process unit.''

For 40 CFR part 60, subpart Ja, the definition of ''refinery process unit'' also impacts the flare provisions. Based on the proposed revisions of ''refinery process unit,'' it was clearly our intent that a broad definition of ''refinery process unit'' should apply to the flare requirements. Specifically, we intended that a flare modification occurs when a wide range of equipment at the petroleum refinery is newly connected to the flare. It was also our intent that the flare management plan consider flare minimization methods for this broadly defined range of equipment referred to collectively as ''refinery process units.''

Based on our review of the impacts of changes to the definition of ''refinery process unit,'' and considering all of the comments received, we maintain that the existing definition of ''refinery process unit'' is broad and should be broadly interpreted. For consistency between 40 CFR part 60, subparts J and Ja, we have elected to maintain the existing definition and not include an example list of refinery process units within the definition. However, to clarify that a modification to a flare occurs when these types of equipment are connected to the flare, we revised the language in the flaring provisions to refer to ''refinery process units, including ancillary equipment.'' This revision is made to clarify our original intent that coke gasification units, storage tanks, product loading operations and wastewater treatment systems, as well as pressure relief valves, pumps, sampling vents, continuous analyzer vents and other similar equipment are units from which a connection to a flare would trigger a flare modification and generate gas streams that should be considered in the flare management plan. We have included in the final amendments a definition of ''ancillary equipment.'' Specifically, *ancillary equipment* means equipment used in conjunction with or that serve a refinery process unit. *Ancillary equipment* includes, but is not limited to, storage tanks, product loading operations, wastewater treatment systems, steam- or electricity-producing units (including coke gasification units), pressure relief valves, pumps, sampling vents, and continuous analyzer vents.

Sulfur recovery plants are also units from which a connection to a flare would trigger a flare modification and generate gas streams that should be considered in the flare management plan. We recognize that on-site sulfur recovery plants are considered refinery process units, and we proposed amendments to the definitions of ''refinery process unit'' and ''sulfur recovery plant'' to clarify that we consider a sulfur recovery plant to be ''a segment of the petroleum refinery in which a specific processing operation is conducted.'' However, the strict definition of ''refinery process unit'' would only apply to sulfur recovery plants physically located at the refinery. As 40 CFR part 60, subpart Ja also applies to off-site sulfur recovery plants (see 40 CFR 60.100(a) and 40 CFR 60.100a(a)), we found it potentially contradictory to define a sulfur recovery plant located outside the refinery as a ''refinery process unit,'' so we are also not finalizing the proposed amendment to include the term ''all refinery process units'' in the definition of ''sulfur recovery plant.'' However, while connections to a refinery flare from an off-site sulfur recovery plant are not expected to be common, off-site sulfur recovery plants are subject to subpart Ja. We clarify in this response that we would consider such a connection to a flare to be from a ''refinery process unit, including ancillary equipment,'' such that connecting an off-site sulfur recovery plant that is subject to subpart Ja to a flare at a refinery would cause that flare to be a modified flare subject to subpart Ja.

Further, in reviewing the definition of ''sulfur recovery plant,'' we noticed an inadvertent error that also suggests that the sulfur recovery plant must be located at a petroleum refinery, which is not consistent with the applicability provisions in 40 CFR 60.100(a) and 40 CFR 60.100a(a). Specifically, we inadvertently omitted the word ''produced'' in this first sentence, so we are amending the definition of ''sulfur recovery plant'' to clarify that a sulfur recovery plant recovers sulfur from sour gases ''produced at the petroleum refinery.'' Thus, we are amending the definition of ''sulfur recovery plant'' to correct inadvertent errors and to clarify that off-site sulfur recovery plants are included in the definition of ''sulfur recovery plant,'' as these plants are expressly considered to be affected facilities in 40 CFR part 60, subpart Ja.

Comment: Commenters supported the revised definition of ''delayed coking unit,'' but stated that, since 40 CFR part 60, subpart Ja only sets standards for the coke drums, the definition should just include the coke drums associated with a single fractionator. The commenters stated that the definition should not include the fractionator itself because VOC emissions from the fractionator are covered by NSPS for equipment leaks.

Response: The proposed amendments to the definition of ''delayed coking unit'' specifically listed the primary components of the delayed coking unit. In particular, based on the operation of the delayed coking unit, we find that the fractionator is an integral part of the delayed coking unit. The fresh feed to the delayed coking unit is generally introduced in the fractionator tower bottoms receiver. This integral use of the fractionator is different than the use of fractionators used for other units defined in 40 CFR part 60, subpart Ja, such as the fluid catalytic cracking unit (FCCU). For the FCCU, fresh feed is introduced in the riser, which is part of the affected facility in subpart Ja. As the feed to the delayed coking unit is to the fractionator, we find that the fractionator is an integral part of the delayed coking unit, so we specifically include it as part of the affected facility. While our proposed amendments covered only the major components of the delayed coking unit, upon our review of the definition based on the comments received, we note that there are several other components of the delayed coking unit that are integral to the operation of the delayed coking unit. Additionally, even though the standards are specific to the coke drum, many of these integral components are interconnected and necessary for the delayed coking unit to meet the applicable standards. Based on our review of the operation of a delayed coking unit, we also include coke cutting and blowdown recovery equipment in the final definition because this equipment is also integral to the overall cyclical operation of the process unit. The definition of ''delayed coking unit'' has been amended in the final rule to mean 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 bottoms receiver and overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; process piping and associated equipment such as pumps, valves and connectors; and the coke drum blowdown recovery compressor system.

Since this definition is more specific than the definition included in the amendments proposed on December 22, 2008, it could affect which delayed coking units are subject to subpart Ja. For example, an owner or operator may have made a change to a delayed coking unit that would not be considered a modification under the December 22, 2008, definition, but that same change could make the delayed coking unit a modified facility subject to subpart Ja using the definition of ''delayed coking unit'' above. In other words, in changing the definition of ''delayed coking unit'' in the final rule, some delayed coking units that would not have been affected sources under the proposed requirements might now be covered by the final rule. Under CAA section 111(a)(2), a ''new source'' is defined from the date of proposal only if there is a standard ''which will be applicable to such source;'' otherwise, a ''new source'' is defined based upon the final rule date. In this circumstance, using the proposal date as the new source date for determining applicability for this group of delayed coking units would be inappropriate as such units would not have been on notice that subpart Ja could apply to them. Accordingly, we moved the ''new source'' date for this group of delayed coking units so that delayed coking units that are only defined as such under the final rule are covered by the final rule only if they commence construction, reconstruction or modification after the promulgation date of these final amendments. The ''new source'' date for other delayed coking units will depend on the previous definitions and when the activities involving the delayed coking unit occurred. See § 60.100a(b) for determining applicability of subpart Ja for delayed coking units.

Comment: One commenter stated that 40 CFR part 63, subpart LLLLL indicates at 40 CFR 63.8681(e) that 40 CFR part 60, subpart J does not apply for asphalt blowing stills subject to subpart LLLLL, and the commenter requested similar clarification for 40 CFR part 60, subpart Ja by exempting this process in 40 CFR 60.100a.

Response: We reviewed the requirement in 40 CFR part 63, subpart LLLLL. Due to the O_2 content of this process gas, we agree that it is not suitable for recovery as fuel gas and subsequent amine treatment; therefore, it is not BSER for combustion controls used on asphalt blowing stills to meet the H_2S concentration limits (or alternative SO_2 emissions limits). We reviewed 40 CFR 60.100a, but we feel a blanket exemption from 40 CFR part 60, subpart Ja is not necessary. Instead, we have included an exemption within the definition of fuel gas similar to the exemptions included for combustion controls on vapors collected and combusted from wastewater treatment and marine vessel loading operations. Specifically, we amended the definition of fuel gas in 40 CFR 60.101a to clarify that fuel gas does not include vapors that are collected and combusted to control emissions from asphalt processing units (*i.e.,* asphalt blowing stills).

Comment: One commenter recommended that the exclusion from the definition of ''fuel gas'' be extended to vapors ''from marine vessel loading operations or waste management units that are collected and combusted'' without any reference to a federal requirement. At a minimum, the commenter stated that marine benzene loading under 40 CFR part 61, subpart BB; the wastewater provisions of 40 CFR part 63, subpart G; remediation efforts regulated under Resource Conservation and Recovery Act (RCRA) corrective action; and RCRA 7003 orders should be added to the exclusion.

Response: We were originally concerned that removing the reference to a federal standard may inadvertently exempt the use of these vapors when used in process heaters or boilers. We determined that it was not BSER to require thermal oxidizers used to comply with the cited federal standards to comply with the H_2S concentration limits due to the typically remote location of the combustion sources (control devices) relative to refinery process units (see technical memorandum entitled *Fuel Gas Treatment of Marine Vessel Loading and Wastewater Treatment Unit Off-gas,* in Docket ID No. EPA–HQ–OAR–2007–0011). However, if these gases are currently routed to a fuel gas system or directly to a process heater or boiler, treatment of the fuel gas to meet the SO_2 emissions limits or the H_2S concentration limits is expected to be economically viable. Additionally, these gases are expected to be only a small portion of the fuel gas combusted in these units, and the refinery has an option to over-treat the primary fuel gas so that gases from the wastewater treatment system or marine vessel loading operation can remain untreated while the fuel gas combustion device itself can comply with the SO_2 emissions limits or the H_2S concentration limits, based on the mixture of fuels used in the device.

In reviewing the rules suggested by the commenter, as well as those we originally listed, we noted that acceptable ''control devices'' or ''combustion units'' in these rules include process heaters and boilers. We did not intend to exclude vapors that are collected and routed to a process heater or boiler to be exempt from the definition of fuel gas. In other words, when developing this exclusion, we specifically considered the combustion of these gases via a thermal oxidizer or flare currently located at the marine vessel loading or wastewater treatment location. These remote combustion devices were really the subject of the analysis, but we did not want to exclude these combustion units themselves because other fuel gas is often fed to these units to ensure adequate combustion of the vapors being controlled. It is clear from our rationale and the description of the exemption included in the preamble of the proposed rule that the exemption was intended ''to exempt vapors that are collected and combusted in an air pollution control device installed to comply with'' specific wastewater or marine vessel loading emissions standards. (72 FR 27180 and also at 27183) Process heaters or boilers would not be ''installed'' to comply with these provisions, and it was not our intent to exclude vapors sent to these types of combustion units. However, the regulatory text is more ambiguous and appears to exclude any vapors collected and combusted, regardless of where they are combusted. As such, we are amending this exclusion to better represent our original intent.

Additionally, with the added clarity in the regulatory text, it seems appropriate to extend this exclusion to control devices used at these locations regardless of why the emission controls were installed. That is, while we originally considered air pollution control devices that were mandated by the EPA, we see no reason to discriminate against air pollution control devices that were installed voluntarily to reduce the emissions from these sources. Further, we intend to clarify that gases off the sour water system, including the sour water stripper, would likely contain higher amounts of reduced sulfur and would be economically viable to treat. Therefore, we are also clarifying that the exemption does not extend to the sour water system. Therefore, the amended definition of ''fuel gas'' in both 40 CFR part 60, subparts J and Ja states that fuel gas ''does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations, or asphalt processing units (*i.e.,* asphalt blowing stills).''

With respect to remediation efforts conducted under RCRA corrective actions, we are unwilling to grant such an exclusion from the definition of ''fuel gas'' in 40 CFR part 60, subpart Ja. First, we anticipate that most vapors from remediation efforts would be low in sulfur and, if so, the owner or operator could apply for the alternative monitoring methods provided in the rule. Also, although some remediation efforts may occur in remote locations, many of the remediation efforts are conducted in reasonable proximity to existing process units. Finally, the range of activities included in RCRA remediation efforts is broad, and we have little information regarding the number and types of RCRA remediation activities that are being conducted. The commenter provided no description of such activities, nor did they provide a reasonable rationale as to why the vapors from these activities should be exempted.

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

A. What are the emission reduction and cost impacts for the final amendments?

The emission reduction and cost impacts presented in this section for flares are revised estimates for the impacts of the final requirements of 40 CFR part 60, subpart Ja for flares, as amended by this action. The table shows the differences in anticipated impacts between these final amendments to subpart Ja and the final June 2008 NSPS requirements of subpart Ja, which were estimated assuming only 40 flares would trigger applicability to the rule. The impacts are presented for 400 affected flares that commence construction, reconstruction or modification that will be required to comply with this final rule. We anticipate that most of the flares would become affected due to the modification provisions for flares set forth in the final June 2008 subpart Ja rule. For this analysis, we assumed that 90 percent of the flares will be modified or reconstructed and 10 percent of the flares will be newly constructed. Further, we estimate that 30 percent of the 400 affected flares, or 120 flares, either would meet the definition of ''emergency flare'' in subpart Ja or would be equipped with a flare gas recovery system such that robust sulfur and flow monitoring would not be required. Therefore, the values in Table 5 of this preamble include the costs and emissions reductions for 400 flares to comply with the flare management plan and root cause and corrective action analyses requirements and for 280 flares to comply with the sulfur and flow monitoring requirements. The cost and emissions reductions for the affected flares to comply with the short-term H_2S concentration of 162 ppmv in the fuel gas are included in the baseline rather than the incremental impacts because this limit is unchanged from the requirements in 40 CFR part 60, subpart J. For further detail on the methodology of these calculations, see *Documentation of Impact Estimates for Fuel Gas Combustion Device and Flare Regulatory Options for Amendments to the Petroleum Refinery NSPS,* in Docket ID No. EPA–HQ–OAR–2007–0011.

We estimate that the final requirements for flares will reduce emissions of SO_2 by 3,200 tons/yr, NO_X by 1,100 tons/yr and VOC by 3,400 tons/yr from the baseline. The estimated annual cost, including annualized capital costs, is a cost savings of about $79 million (2006 dollars) due to the replacement of some natural gas purchases with recovered flare gas and the retention of intermediate and product streams due to a reduction in the number of malfunctions associated with refinery process units and ancillary equipment connected to the flare. Note that not all refiners will realize a cost savings since we only estimate that refineries with high flare flows will install vapor recovery systems. Although the rule does not specifically require installation of flare gas recovery systems, we project that owners and operators of flares receiving high waste gas flows will conclude, upon installation of monitors, implementation of their flare management plans, and implementation of root causes analyses, that installing flare gas recovery would result in fuel savings by using the recovered flare gas where purchased natural gas is now being used to fire equipment such as boilers and process heaters. The flare management plan requires refiners to conduct a thorough review of the flare system so that flare gas recovery systems are installed and used where these systems are warranted. As part of the development of the flare management plan, refinery owners and operators must provide rationale and supporting evidence regarding the flare waste gas reduction options considered, the quantity of flare gas that would be recovered or prevented by the option, the BTU content of the flare gas and the ability or inability of the reduction option to offset natural gas purchases. In addition, consistent with Executive Order 13563 (Improving Regulation and Regulatory Review, issued on January 18, 2011), for facilities implementing flare gas recovery, we are finalizing provisions that would allow the owner or operator to reduce monitoring costs and the number of root cause analyses, corrective actions, and corresponding recordkeeping and reporting they would need to perform. We estimate that the final requirements for flares will reduce emissions of SO_2 by 3,200 tons/yr, NO_X by 1,100 tons/yr and VOC by 3,400 tons/yr from the baseline. The overall cost effectiveness is a cost savings of about $10,000 per ton of combined pollutants removed. The estimated nationwide 5-year emissions reductions and cost impacts for the final standards are summarized in Table 5 of this preamble.

TABLE 5—NATIONAL EMISSION REDUCTIONS AND COST IMPACTS FOR PETROLEUM REFINERY FLARES SUBJECT TO AMENDED STANDARDS UNDER 40 CFR PART 60, SUBPART JA

[Fifth year after the effective date of these final rule amendments] [a]

Subpart Ja requirements	Total capital cost ($1,000)	Total annual cost without credit ($1,000/yr)	Natural gas offset/product recovery credit ($1,000)	Total annual cost ($1,000/yr)	Annual emission reductions (tons SO$_2$/yr)	Annual emission reductions (tons NO$_X$/yr)	Annual emission reductions (tons VOC/yr)	Cost effectiveness ($/ton emissions reduced)
Estimates from June 2008 Final Rule	40,000	....	....	(7,000)	80	6	200	(23,000)
Revised Estimates for Amendments	460,000	100,000	(180,000)	(79,000)	3,200	1,100	3,400	(10,000)

[a] All costs in this table are relative to the baseline used for the 2008 final rule.

We also estimate that the final requirements for flares will result in emissions reduction co-benefits of CO$_2$ equivalents by 1,900,000 metric tonnes per year, predominantly as a result of our estimate of the largest flares employing flare gas recovery and to a lesser extent, as a result of the root cause analyses applicable to all flares.

The cost, environmental and economic impacts for the final amendments to 40 CFR part 60, subpart Ja for process heaters are not expected to be different than those reported for the final June 2008 standards. We expect owners and operators to install the same technology to meet these final amendments that we anticipated they would install to meet the June 2008 final subpart Ja requirements (*i.e.,* ultra-low NO$_X$ burners). We did revise our emission estimates based on the type of process heater, creating separate impacts for forced draft process heaters and natural draft process heaters. Dividing process heaters into separate subcategories, based on the draft type, required us to develop new distributions of baseline emissions for each type of process heater. The baseline emission estimates for natural draft process heaters are slightly lower than those developed for the existing subpart Ja requirements (per affected process heater), but the average emission reduction achieved by ultra-low NO$_X$ burners was adjusted to 80 percent (rather than 75 percent used for generic process heaters). For forced draft process heaters, the baseline (*i.e.,* uncontrolled) emissions rate for forced draft process heaters was revised slightly upward, based on the available emissions data. Due to these differences, the mix of controls needed to meet a 40 ppmv emissions limit was no longer cost effective for forced draft process heaters, but the emission reductions associated with process heaters complying with the 60 ppmv standard were higher than those previously estimated for generic process heaters. Thus, the creation of new subcategories of process heaters with different emissions limits for each subcategory did not impact the control or compliance methods used by the facilities (*i.e.,* BSER in all cases was based on the performance of advanced combustion monitoring controls in conjunction with ultra-low NO$_X$ burners) and did not change the estimated compliance costs. As we do not have adequate data regarding the prevalence of natural draft process heaters versus forced draft process heaters that will become subject to the rule, we used the emission reductions estimated for the two different types of process heaters as a means to bound the range of anticipated NO$_X$ emission reductions to be from 7,100 to 8,600 tons/yr in the fifth year after the effective date of this final rule (see *Revised NO$_X$ Impact Estimates for Process Heaters,* in Docket ID No. EPA–HQ–OAR–2007–0011). We estimated the emission reductions to be 7,500 tons/yr for the June 2008 final standards, which falls well within the anticipated range of emissions reductions for the standards we are finalizing here. Given the uncertainty in the emissions estimates, as well as the uncertainty in the relative number of natural draft process heaters versus forced draft process heaters, we concluded that the impacts previously developed for subpart Ja accurately represent the impacts for process heaters in these final amendments.

We note that, in the preamble to the June 2008 final standards, we estimated costs and emissions reductions for 30 fuel gas combustion devices, but we subsequently determined that those estimates did not fully account for the number of affected flares (which, at the time, were considered a subset of fuel gas combustion devices). Therefore, in the preamble to the December 2008 proposed amendments, we presented revised emission reduction and cost estimates for affected fuel gas combustion devices. As previously explained, we are not finalizing the long-term 60 ppmv H$_2$S fuel gas concentration limit for flares, as proposed, and we revised our cost estimates accordingly. Because these final amendments consider flares to be a separate affected source, the emission reductions and costs for fuel gas combustion devices are not affected by these final amendments and are not included in this preamble. Rather, the final emission reduction and cost estimates for fuel gas combustion devices are very close to the impacts presented in the June 2008 final rule; the details of the analysis and the final impacts are presented in *Documentation of Impact Estimates for Fuel Gas Combustion Device and Flare Regulatory Options for Amendments to the Petroleum Refinery NSPS,* in Docket ID No. EPA–HQ–OAR–2007–0011.

The final amendments to 40 CFR part 60, subpart J are technical corrections or clarifications to the existing rule and should have no negative emissions impacts.

B. What are the economic impacts?

The total annualized compliance costs are estimated to save about $79 million (2006 dollars) in the fifth year after the effective date of these final amendments. Note that not all refiners will realize a cost savings as only flare systems with high waste gas flows (about 10 percent of all flares) are expected to install vapor recovery systems. Alternatively, if no refineries install flare gas recovery systems, total annualized compliance costs are estimated to be $10.7 million (2006 dollars) in the fifth year after proposal. Regardless of whether any refineries install flare gas recovery systems, we do not anticipate any adverse economic impacts associated with this regulatory action, as no increase in refined petroleum product prices or decrease in refined petroleum product output is expected.

For more information, please refer to the Regulatory Impact Analysis (RIA) that is in the docket for this final rule.

C. What are the benefits?

Emission controls installed to meet the requirements of this rule will generate benefits by reducing emissions of criteria pollutants and their precursors, including SO_2, NO_X and VOC as well as CO_2. SO_2, NO_X and VOC are precursors to $PM_{2.5}$ (particles smaller than 2.5 microns), and NO_X and VOC are precursors to ozone. For this rule, we were only able to quantify the health benefits associated with reduced exposure to $PM_{2.5}$ from emission reductions of SO_2 and NO_X and the climate benefits associated with CO_2 emission reductions. We estimate the monetized benefits of this final regulatory action to be $270 million to $580 million (2006 dollars, 3-percent discount rate) in the fifth year (2017). The benefits at a 7-percent discount rate for health benefits and 3-percent discount rate for climate benefits are $240 million to $530 million (2006 dollars). For small flares only, we estimate the monetized benefits are $170 million to $410 million (3-percent discount rate) and $150 million to $370 million (7-percent discount rate for health benefits and 3-percent discount rate for climate benefits). For large flares only, we estimate the monetized benefits are $93 million to $160 million (3-percent discount rate) and $88 million to $150 million (7-percent discount rate for health benefits and 3-percent discount rate for climate benefits). Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[12] A summary of the monetized benefits estimates by pollutant for all flares at discount rates of 3 percent and 7 percent is in Table 6 of this preamble. Several benefits categories, including direct exposure to SO_2 and NO_X benefits, ozone benefits, ecosystem benefits and visibility benefits are not included in these monetized benefits. All estimates are in 2006 dollars for the year 2017.

TABLE 6—SUMMARY OF THE MONETIZED $PM_{2.5}$ AND CO_2 BENEFITS FOR AMENDED PETROLEUM REFINERIES STANDARDS

[Millions of 2006 dollars] [a]

Pollutant	Emission reductions (tons per year)	Total monetized benefits (3-percent discount)	Total monetized benefits (7-percent discount)
With Flare Gas Recovery			
$PM_{2.5}$ Benefits[b]:			
SO_2	3,200	$210 to $510	$190 to $460.
NO_X	1,100	$7.1 to $18	$6.4 to $16.
PM Total		$220 to $530	$190 to $480.
CO_2 Benefits[c]	1,900,000[d]	$46	$46.
Total Monetized Benefits:		$260 to $580	$240 to $520.
Without Flare Gas Recovery			
$PM_{2.5}$ Benefits[b]:			
SO_2	2,900	$190 to $450	$170 to $410.
NO_X	56	$0.36 to $0.87	$0.32 to $0.78.
PM Total		$190 to $460	$170 to $410.
CO_2 Benefits[c]	110,000[d]	$2.6	$2.6.
Total Monetized Benefits		$190 to $460	$170 to $410.

[a] All estimates are for the analysis year (2017) and are rounded to two significant figures so numbers may not sum across rows. The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as NO_X and SO_2, as well as CO_2. It is important to note that the monetized benefits do not include reduced health effects from direct exposure to SO_2 and NO_X, ozone exposure, ecosystem effects or visibility impairment.

[b] PM benefits are shown as a range from Pope, *et al.* (2002) to Laden, *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type.

[c] The CO_2 emission reductions (shown in metric tonnes) have been reduced to reflect the anticipated emission increases associated with the energy disbenefits. CO_2-related benefits were calculated using the social cost of carbon (SCC), which is discussed further in the RIA. The net present value of reduced CO_2 emissions is calculated differently than other benefits. This table shows monetized climate benefits using the global average SCC estimate at a 3-percent discount rate because the interagency workgroup deemed the SCC at a 3-percent discount rate to be the central value. In the RIA, we also provide the monetized CO_2 benefits using discount rates of 5 percent (average), 2.5 percent (average) and 3 percent (95th percentile).

[d] Metric tonnes

These benefits estimates represent the total monetized human health benefits for populations exposed to less $PM_{2.5}$ in 2017 from controls installed to reduce air pollutants in order to meet this rule. To estimate human health benefits of this rule, the EPA used benefit-per-ton factors to quantify the changes in $PM_{2.5}$-related health impacts and monetized benefits based on changes in SO_2 and NO_X emissions. These benefit-per-ton factors were derived using the general approach and methodology laid out in Fann, Fulcher, and Hubbell (2009).[13] This approach uses a model to convert emissions of $PM_{2.5}$ precursors into changes in ambient $PM_{2.5}$ levels and another model to estimate the changes in human health associated with that change in air quality, which are then divided by the emission reductions to

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[12] Roman, *et al.*, 2008. *Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S.,* Environ. Sci. Technol., 42, 7, 2268—2274.

[13] Fann, N., C.M. Fulcher, B.J. Hubbell. 2009. *The Influence of Location, Source, and Emission Type in Estimates of the Human Health Benefits of Reducing a Ton of Air Pollution.* Air Qual Atmos Health (2009) 2:169–176.

create the benefit-per-ton estimates. However, for this rule, we use air quality modeling data specific to the petroleum refineries sector.[14] The primary difference between the estimates used in this analysis and the estimates reported in Fann, Fulcher, and Hubbell (2009) is the air quality modeling data utilized. While the air quality data used in Fann, Fulcher, and Hubbell (2009) reflects broad pollutant/source category combinations, such as all non-electric generating unit stationary point sources, the air quality modeling data used in this analysis is sector-specific. In addition, the updated air quality modeling data reflects more recent emissions data (2005 rather than 2001) and has a higher spatial resolution (12 kilometers (km) rather than 36 km grid cells). As a result, the benefit-per-ton estimates presented herein better reflect the geographic areas and populations likely to be affected by this sector. The benefits methodology, such as health endpoints assessed, risk estimates applied and valuation techniques applied did not change. However, these updated estimates still have similar limitations as all national-average benefit-per-ton estimates in that they reflect the geographic distribution of the modeled emissions, which may not exactly match the emission reductions in this rulemaking, and they may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates or other local factors for any specific location.

We apply these national benefit-per-ton estimates calculated for this sector separately for SO_2 and NO_X and multiply them by the corresponding emission reductions. The sector-specific modeling does not provide estimates of the $PM_{2.5}$-related benefits associated with reducing VOC emissions, but these unquantified benefits are generally small compared to other $PM_{2.5}$ precursors. More information regarding the derivation of the benefit-per-ton estimates for the petroleum refining sector is available in the technical support document, which is available in the docket.

These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type. The main $PM_{2.5}$ precursors affected by this rule are SO_2 and NO_X. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. For example, SO_2 has a lower benefit-per-ton estimate than direct $PM_{2.5}$ because it does not form as much $PM_{2.5}$, thus, the exposure would be lower, and the monetized health benefits would be lower.

It is important to note that the magnitude of the $PM_{2.5}$ benefits is largely driven by the concentration response function for premature mortality. Experts have advised the EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. We cite two key empirical studies, one based on the American Cancer Society cohort study [15] and the extended Six Cities cohort study.[16] In the RIA for this final rule, which is available in the docket, we also include benefits estimates derived from the expert judgments and other assumptions.

The EPA strives to use the best available science to support our benefits analyses. We recognize that interpretation of the science regarding air pollution and health is dynamic and evolving. After reviewing the scientific literature, we have determined that the no-threshold model is the most appropriate model for assessing the mortality benefits associated with reducing $PM_{2.5}$ exposure. Consistent with this finding, we have conformed the previous threshold sensitivity analysis to the current state of the PM science by incorporating a new ‘‘Lowest Measured Level’’ (LML) assessment in the RIA accompanying this rule. While an LML assessment provides some insight into the level of uncertainty in the estimated PM mortality benefits, the EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations.

Most of the estimated PM-related benefits in this rule would accrue to populations exposed to higher levels of $PM_{2.5}$. For this analysis, policy-specific air quality data is not available due to time or resource limitations, thus, we are unable to estimate the percentage of premature mortality associated with this specific rule's emission reductions at each $PM_{2.5}$ level. As a surrogate measure of mortality impacts, we provide the percentage of the population exposed at each $PM_{2.5}$ level using the source apportionment modeling used to calculate the benefit-per-ton estimates for this sector. Using the Pope, *et al.* (2002) study, 77 percent of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 7.5 micrograms per cubic meter ($\mu g/m^3$). Using the Laden, *et al.* (2006) study, 25 percent of the population is exposed above the LML of 10 $\mu g/m^3$. It is important to emphasize that we have high confidence in $PM_{2.5}$-related effects down to the lowest LML of the major cohort studies. This fact is important, because, as we model avoided premature deaths among populations exposed to levels of $PM_{2.5}$, we have lower confidence in levels below the LML for each study.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage) and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, we believe the benefit analysis for this rule provides a reasonable indication of the expected health benefits of the rulemaking under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2006 $PM_{2.5}$ NAAQS RIA because we lack the necessary air quality input and monitoring data to run the benefits model. In addition, we have not conducted air quality modeling for this rule, and using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2006 $PM_{2.5}$ NAAQS benefits analysis [17] provides an indication of the sensitivity of our results to various assumptions.

This rule is expected to reduce CO_2 emissions from the electricity sector. The EPA has assigned a dollar value to reductions in CO_2 emissions using recent estimates of the ‘‘social cost of carbon’’ (SCC). The SCC is an estimate

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[14] U.S. Environmental Protection Agency. 2011. *Technical Support Document: Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from the Petroleum Refineries Sector.* EPA, Research Triangle Park, NC.

[15] Pope, *et al.*, 2002. *Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution.* Journal of the American Medical Association 287:1132–1141.

[16] Laden, *et al.*, 2006. *Reduction in Fine Particulate Air Pollution and Mortality.* American Journal of Respiratory and Critical Care Medicine 173: 667–672.

[17] U.S. Environmental Protection Agency, 2006. *Final Regulatory Impact Analysis: $PM_{2.5}$ NAAQS.* Prepared by Office of Air and Radiation. October. Available on the Internet at *http://www.epa.gov/ttn/ecas/ria.html.*

of the monetized damages associated with an incremental increase in carbon emissions in a given year or the per metric ton benefit estimate relating to decreases in CO_2 emissions. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damage from increased flood risk, and the value of ecosystem services due to climate change.

The SCC estimates used in this analysis were developed through an interagency process that included the EPA and other executive branch entities, and that concluded in February 2010. We first used these SCC estimates in the benefits analysis for the final joint EPA/DOT Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; see the rule's preamble for discussion about application of the SCC (75 FR 25324; May 7, 2010). The SCC Technical Support Document (SCC TSD) provides a complete discussion of the methods used to develop these SCC estimates.[18]

The interagency group selected four SCC values for use in regulatory analyses, which we have applied in this analysis: $5.9, $24.3, $39, and $74.4 per metric ton of CO_2 emissions in 2016, in 2007 dollars. The first three values are based on the average SCC from three integrated assessment models, at discount rates of 5, 3 and 2.5 percent, respectively. Social cost of carbon values at several discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the SCC from all three values at a 3-percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the extremes of the SCC distribution. Low probability, high impact events are incorporated into all of the SCC values through explicit consideration of their effects in two of the three values as well as the use of a probability density function for equilibrium climate sensitivity. Treating climate sensitivity probabilistically results in more high temperature outcomes, which in turn leads to higher projections of damages.

Applying the global SCC estimates using a 3-percent discount rate, we estimate the value of the climate related benefits of this rule in 2017 is $49 million (2006$), as shown in Table 6. See the RIA for more detail on the methodology used to calculate these benefits and additional estimates of climate benefits using different discount rates and the 95th percentile of the 3-percent discount rate SCC. Important limitations and uncertainties of the SCC approach are also described in the RIA.

It should be noted that the monetized benefits estimates provided above do not include benefits from several important benefit categories, including direct exposure to SO_2 and NO_X, ozone exposure, ecosystem effects and visibility impairment. Although we do not have sufficient information or modeling available to provide monetized estimates for this rulemaking, we include a qualitative assessment of these unquantified benefits in the RIA for this final rule.

Although this final rule provides refiners with some additional compliance options and removes some requirements, such as the long-term H_2S limit for flares, these are non-monetized benefits of the rule.

For more information on the benefits analysis, please refer to the RIA for this rulemaking, which is available in the docket.

VI. Statutory and Executive Order Reviews

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

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action. In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action.

A summary of the monetized benefits, compliance costs and net benefits for the final rule at discount rates of 3 percent and 7 percent is in Table 7 of this preamble.

TABLE 7—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS AND NET BENEFITS FOR THE FINAL PETROLEUM REFINERIES NSPS IN 2017

[Millions of 2006 dollars] [a]

	3-Percent discount rate	7-Percent discount rate
Total Monetized Benefits [b]	$270 to $580	$240 to $530.
Total Compliance Costs [c]	−$79	−$79.
Net Benefits	$340 to $660	$320 to $610.
Non-Monetized Benefits	Health effects from direct exposure to SO_2 and NO_2.	
	Health effects from $PM_{2.5}$ exposure from VOC	
	Ecosystem effects.	
	Visibility impairment.	

[a] All estimates are for the implementation year (2017) and are rounded to two significant figures.

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[18] Docket ID EPA–HQ–OAR–2009–0472–114577, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon,* with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at *http://epa.gov/otaq/climate/regulations.htm.*

[b] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as NO_X and SO_2, as well as CO_2 benefits. It is important to note that the monetized benefits do not include the reduced health effects from direct exposure to SO_2 and NO_X, ozone exposure, ecosystem effects or visibility impairment. Human health benefits are shown as a range from Pope, *et al.* (2002) to Laden, *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type. The net present value of reduced CO_2 emissions is calculated differently than other benefits. This table includes monetized climate benefits using the global average social cost of carbon (SCC) estimated at a 3-percent discount rate because the interagency work group deemed the SCC estimate at a 3-percent discount rate to be the central value.

[c] The engineering compliance costs are annualized using a 7-percent discount rate.

To support the determination of BSER for the June 24, 2008, final rule, we considered a number of regulatory options and their costs and benefits. Those results are presented in the RIA for the June 24, 2008, final rulemaking, which is available in the docket. These final rule amendments are in response to comments received on the December 22, 2008, proposed rule amendments. Costs and benefits associated with the amendments in this final rule differ from the June 24, 2008, final rule and the December 22, 2008, proposed rule amendments primarily as a result of correcting the number of flares projected to have to comply with this rule (*i.e.,* 400 affected flares in this rule compared to 40 estimated in the June 24, 2008, final rule and 150 in the December 22, 2008, proposed amendments). In addition, the amendments in this final rule to address comments received for the other fuel gas combustion devices do not affect the projected costs and benefits from the December 22, 2008, proposal, which also did not change from the June 24, 2008, final rule. Therefore, for purposes of developing these final rule amendments, we did not re-evaluate the suite of regulatory options for flares and other fuel gas combustion devices considered to support the June 24, 2008, final rule. However, even with the flare count adjustment, this final rule is consistent with Executive Order 13563 (Improving Regulation and Regulatory Review) because the monetized benefits of this final rule exceed the costs. In addition, for facilities implementing flare gas recovery, we are reducing regulatory burden by finalizing provisions that would allow the owner or operator to reduce monitoring costs and the number of root cause analyses, corrective actions and corresponding recordkeeping and reporting they would need to perform.

For more information on the cost-benefits analysis, please refer to the RIA for this rulemaking, which is available in the docket.

B. Paperwork Reduction Act

The final amendments to the Standards of Performance for Petroleum Refineries (40 CFR part 60, subpart J) do not impose any new information collection burden. The final amendments are clarifications and technical corrections that do not affect the estimated burden of the existing rule. Therefore, we have not revised the ICR for the existing rule. However, OMB has previously approved the information collection requirements contained in the existing rule (40 CFR part 60, subpart J) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.,* and has assigned OMB control number 2060–0022. The OMB control numbers for the EPA's regulations are listed in 40 CFR part 9.

The OMB has approved the information collection requirements in the amendments to the Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (40 CFR part 60, subpart Ja) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.,* and has assigned OMB control number 2060–0602.

The information requirements in these final amendments add new compliance options, provide more time to comply with the requirements for flares, clarify the flare management plan requirements and clarify the flare modification provision. Overall, these changes are expected to reduce the costs associated with testing, monitoring, recording and reporting, so they will not result in any increase in burden for the affected facilities for which the EPA previously estimated the burden. However, the EPA has revised the number of flares expected to become subject to the rule over the first 3 years of the ICR. Therefore, the annual burden was estimated for the additional affected facilities. The total burden for 40 CFR part 60, subpart Ja can be estimated by summing the previously approved annual burden for OMB control number 2060–0602 (5,340 labor-hours per year at a cost of $481,249 per year, annualized capital costs of $2,052,000 per year, and operation and maintenance costs of $1,117,440 per year) and the annual burden for this ICR, as described below.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 54,572 labor-hours per year at a cost of $4,918,110 per year. The annualized capital costs are estimated at $11,266,000 per year and operation and maintenance costs are estimated at $8,750,000 per year. We note that the capital costs, as well as the operation and maintenance costs, are for the continuous monitors; these costs are also included in the cost impacts presented in section V.A of this preamble. Therefore, the burden costs associated with the continuous monitors presented in the ICR are not additional costs incurred by affected sources subject to final 40 CFR part 60, subpart Ja. 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 are listed in 40 CFR part 9. The EPA is amending the table in 40 CFR part 9 of currently approved ICR control numbers for various regulations to list regulatory citations for the information requirements contained in this final rule. This amendment updates the table to list the information collection requirements being promulgated here as amendments to the NSPS for petroleum refineries.

The EPA will continue to present OMB control numbers in a consolidated table format to be codified in 40 CFR part 9 of the agency's regulations and in each CFR volume containing the EPA regulations. The table lists the section numbers with reporting and recordkeeping requirements and the current OMB control numbers. This listing of the OMB control numbers and their subsequent codification in the CFR satisfy the requirements of the Paperwork Reduction Act (44 U.S.C. 3501, *et seq.*) and OMB's implementing regulations at 5 CFR part 1320.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule would not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations and small governmental jurisdictions.

For purposes of assessing the impact of this final action on small entities, small entity is defined as: (1) A small business whose parent company has no more than 1,500 employees, that is primarily engaged in refining crude petroleum into refined petroleum as defined by NAICS code 32411 (as defined by Small Business Administration size standards); (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.

While we estimated the natural gas recovery offsets or credit at a national level and believe that larger firms are more likely to offset natural gas purchases, the revenues from natural gas recovery offsets might mask disproportionate impacts on small refiners. To better identify disproportionate impacts, we examined the potential impacts on refiners based on a scenario where no firms adopt flare gas recovery systems and comply with the NSPS through flare monitoring and flare management and root cause analysis actions. The incremental compliance costs imposed on small refineries are not estimated to create significant impacts on a cost-to-sales ratio basis at the firm level. Therefore, no adverse economic impacts are expected for any small or large entity.

After considering the economic impacts of these final amendments on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The small entities directly regulated by these final amendments are small petroleum refineries. We have determined that 31 small refiners, or 55 percent of total refiners, will experience an impact of between less than 0.01 percent up to 0.63 percent of revenues.

D. Unfunded Mandates Reform Act

This rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any one year. The costs of the final amendments would not increase costs associated with the final rule. Thus, this rule is not subject to the requirements of sections 202 or 205 of the UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. The final amendments contain no requirements that apply to such governments and impose no 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, as specified in Executive Order 13132. This action does not modify existing responsibilities or create new responsibilities among EPA Regional offices, states or local enforcement agencies. Thus, Executive Order 13132 does not apply to this action.

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). The final amendments impose no requirements on tribal governments. 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 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is based solely on technology performance.

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

This action is not a ‘‘significant energy action’’ as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. The final amendments would not increase the level of energy consumption required for the final rule and may decrease energy requirements.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities, unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (*e.g.,* materials specifications, test methods, sampling procedures and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the agency decides not to use available and applicable VCS.

This rulemaking involves technical standards. The EPA has decided to use the following VCS for determining the higher heating value of fuel fed to process heaters: ASTM D240–02 (Reapproved 2007), *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter;* ASTM D1826–94 (Reapproved 2003), *Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter;* ASTM D3588–98 (Reapproved 2003), *Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels;* ASTM D4809–06, *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method);* ASTM D4891–89 (Reapproved 2006), *Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion;* ASTM D1945–03 (Reapproved 2010), *Standard Method for Analysis of Natural Gas by Gas Chromatography;* and ASTM D1946–90 (Reapproved 2006), *Standard Method for Analysis of Reformed Gas by Gas Chromatography.*

The EPA has decided to use the following VCS as acceptable alternatives to EPA Methods 2, 2A, 2B, 2C or 2D for conducting relative accuracy evaluations of fuel gas flow monitors: American Society of Mechanical Engineers (ASME) MFC–3M–2004, *Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi;* ANSI/ASME MFC–4M–1986 (Reaffirmed 2008), *Measurement of Gas Flow by Turbine Meters;* ASME MFC–6M–1998 (Reaffirmed 2005), *Measurement of Fluid Flow in Pipes Using Vortex Flowmeters;* ASME/ANSI MFC–7M–1987 (Reaffirmed 2006), *Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles;* ASME MFC–11M–2006, *Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters;* ASME MFC–14M–2003, *Measurement of Fluid Flow Using Small Bore Precision Orifice Meters;* and ASME MFC–18M–2001, *Measurement of Fluid Flow Using Variable Area Meters.*

The EPA has also decided to use the following VCS as acceptable alternatives to EPA Methods 2, 2A, 2B, 2C or 2D for conducting relative accuracy evaluations of fuel oil flow monitors: ANSI/ASME MFC–5M–1985 (Reaffirmed 2006), *Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters;* ASME/ANSI MFC–9M–1988 (Reaffirmed 2006), *Measurement of Liquid Flow in Closed Conduits by Weighing Method;* ASME MFC–16–2007, *Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters;* ASME MFC–22–2007, *Measurement of Liquid by Turbine Flowmeters;* and ISO 8316: *Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987–10–01)—First Edition.*

The EPA has decided to use the following VCS as acceptable alternatives to EPA Method 15A and 16A for conducting relative accuracy evaluations of monitors for reduced sulfur compounds, total sulfur compounds, and H_2S: ANSI/ASME PTC 19.10–1981, *Flue and Exhaust Gas Analyses.* The EPA has decided to use the following VCS as acceptable alternatives to EPA Method 16A for analysis of total sulfur samples: ASTM D4468–85 (Reapproved 2006), *Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry;* and ASTM D5504–08, *Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence.*

The EPA has decided to use the following VCS as acceptable alternatives to EPA Method 18 for relative accuracy evaluations of gas composition analyzers for gas-fired process heaters: ASTM D1945–03 (Reapproved 2010), *Standard Method for Analysis of Natural Gas by Gas Chromatography;* ASTM D1946–90 (Reapproved 2006), *Standard Method for Analysis of Reformed Gas by Gas Chromatography;* ASTM UOP539–97, *Refinery Gas Analysis by Gas Chromatography;* and ASTM D6420–99 (Reapproved 2004), *Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry.* However, ASTM D6420–99 is a suitable alternative to EPA Method 18 only where:

(1) The target compound(s) are those listed in Section 1.1 of ASTM D6420–99, and

(2) The target concentration is between 150 parts per billion by volume and 100 ppmv.

For target compound(s) not listed in Section 1.1 of ASTM D6420–99, but potentially detected by mass spectrometry, the regulation specifies that the additional system continuing calibration check after each run, as detailed in Section 10.5.3 of the ASTM method, must be followed, met, documented and submitted with the data report even if there is no moisture condenser used or the compound is not considered water soluble. For target compound(s) not listed in Section 1.1 of ASTM D6420–99 and not amenable to detection by mass spectrometry, ASTM D6420–99 does not apply.

These above-listed VCS are incorporated by reference (see 40 CFR 60.17).

The EPA has also decided to use American Gas Association *Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines* (1990), American Gas Association *Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 2: Specification and Installation Requirements* (2000), American Gas Association *Report No. 11: Measurement of Natural Gas by Coriolis Meter* (2003), American Gas Association *Transmission Measurement Committee Report No. 7, Measurement of Natural Gas by Turbine Meters* (Revised February 2006) and API's *Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices,* First Edition, August 2005, for conducting relative accuracy evaluations of fuel gas flow monitors; Gas Processors Association (GPA) Standard 2261–00, *Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography* (2000), for relative accuracy evaluations of gas composition analyzers for gas-fired process heaters; and GPA 2172–09, *Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer,* for determining the higher heating value of fuel fed to process heaters. These methods are also incorporated by reference (see 40 CFR 60.17).

While the agency has identified five VCS as being potentially applicable to this rule, we have decided not to use these VCS in this rulemaking. The use of these VCS would be impractical because they do not meet the objectives of the standards cited in this rule. See the docket for this rule for the reasons for these determinations.

Under 40 CFR 60.13(i) of the NSPS General Provisions, 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 the final rule and amendments.

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 United States.

The EPA has determined that this final rule 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. The final amendments are either clarifications or compliance alternatives which will neither increase or decrease environmental protection.

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 Congress and to the Comptroller General of the United States. The EPA will submit a report containing these final rules and other required information to the United States Senate, the United States House of Representatives and the Comptroller General of the United States prior to publication of the final rules in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). This final rule will be effective on November 13, 2012.

List of Subjects

40 CFR Part 9

Environmental protection, Reporting and recordkeeping requirements.

40 CFR Part 60

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

Dated: June 1, 2012.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 9—[AMENDED]

■ 1. The authority citation for part 9 continues to read as follows:

Authority: 7 U.S.C. 135, *et seq.,* 136–136y; 15 U.S.C. 2001, 2003, 2005, 2006, 2601–2671; 21 U.S.C. 331j, 346a, 348; 31 U.S.C. 9701; 33 U.S.C. 1251, *et seq.,* 1311, 1313d, 1314, 1318, 1321, 1326, 1330, 1342, 1344, 1345(d) and (e), 1361; E.O. 11735, 38 FR 21243, 3 CFR, 1971–1975 Comp. p. 973; 42 U.S.C. 241, 242b, 243, 246, 300f, 300g, 300g–1, 300g–2, 300g–3, 300g–4, 300g–5, 300g–6, 300j–1, 300j–2, 300j–3, 300j–4, 300j–9, 1857, *et seq.,* 6901–6992k, 7401–7671q, 7542, 9601–9657, 11023, 11048.

■ 2. The table in Section 9.1 is amended by adding an entry in numerical order for 60.103a–60.108a under the heading ''Standards of Performance for New Stationary Sources'' to read as follows:

§ 9.1 OMB Approvals under the Paperwork Reduction Act.

* * * * *

40 CFR citation	OMB control No.
* * *	* *
Standards of Performance for New Stationary Sources[1]	
* * *	* *
60.103a–60.108a	2060–0602
* * *	* *

[1] The ICRs referenced in this section of the table encompass the applicable general provisions contained in 40 CFR part 60, subpart A, which are not independent information collection requirements.

* * * * *

PART 60—[AMENDED]

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

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

Subpart A—[AMENDED]

■ 4. Section 60.17 is amended by:

■ a. Revising paragraphs (a)(84), (a)(95), (a)(96), (a)(97), and (a)(98);

■ b. Adding paragraphs (a)(100) through (a)(108);

■ c. Adding paragraph (c)(2);

■ d. Revising paragraph (h)(4) and adding paragraphs (h)(5) through (h)(15);

■ e. Adding paragraphs (m)(2) and (m)(3); and

■ f. Adding paragraphs (p) and (q) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(84) ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, (Approved October 1, 2004), IBR approved for § 60.107a(d) of subpart Ja and table 2 of subpart JJJJ of this part.

* * * * *

(95) ASTM D3588–98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, (Approved May 10, 2003), IBR approved for §§ 60.107a(d) and 60.5413(d).

(96) ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, (Approved June 1, 2006), IBR approved for §§ 60.107a(d) and 60.5413(d).

(97) ASTM D1945–03 (Reapproved 2010), Standard Method for Analysis of Natural Gas by Gas Chromatography, (Approved January 1, 2010), IBR approved for §§ 60.107a(d) and 60.5413(d).

(98) ASTM D5504–08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, (Approved June 15, 2008), IBR approved for §§ 60.107a(e) and 60.5413(d).

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(100) ASTM D4468–85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry (Approved June 1, 2006), IBR approved for § 60.107a(e).

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

(102) ASTM D1826–94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, (Approved May 10, 2003), IBR approved for § 60.107a(d).

(103) ASTM D1946–90 (Reapproved 2006), Standard Method for Analysis of Reformed Gas by Gas Chromatography, (Approved June 1, 2006), IBR approved for § 60.107a(d).

(104) ASTM D4809–06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), (Approved December 1, 2006), IBR approved for § 60.107a(d).

(105) ASTM UOP539–97, Refinery Gas Analysis by Gas Chromatography, (Copyright 1997), IBR approved for § 60.107a(d).

(106) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008), IBR approved for §§ 60.41b of subpart Db and 60.41c of subpart Dc of this part.

(107) 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 of subpart Db and 60.41c of subpart Dc of this part.

(108) 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 of subpart Db and 60.41c of subpart Dc of this part.

* * * * *

(c) * * *

(2) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22-Testing Protocol, Section 2-Differential Pressure Flow Measurement Devices, First Edition, August 2005, IBR approved for § 60.107a(d) of subpart Ja of this part.

* * * * *

(h) * * *

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], (Issued August 31, 1981), IBR approved for § 60.56c(b), § 60.63(f), § 60.106(e), § 60.104a(d), (h), (i), and (j), § 60.105a(d), (f), and (g), § 60.106a(a), § 60.107a(a), (c), and (e), tables 1 and 3 of subpart EEEE, tables 2 and 4 of subpart FFFF, table 2 of subpart JJJJ, §§ 60.4415(a), 60.2145(s), 60.2145(t),

60.2710(s), 60.2710(t), 60.2710(w), 60.2730(q), 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, §§ 60.5406(c) and 60.5413(b).

(5) ASME MFC–3M–2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, IBR approved for § 60.107a(d) of subpart Ja of this part.

(6) ANSI/ASME MFC–4M–1986 (Reaffirmed 2008), Measurement of Gas Flow by Turbine Meters, IBR approved for § 60.107a(d) of subpart Ja of this part.

(7) ANSI/ASME–MFC–5M–1985 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, IBR approved for § 60.107a(d) of subpart Ja of this part.

(8) ASME MFC–6M–1998 (Reaffirmed 2005), Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, IBR approved for § 60.107a(d) of subpart Ja of this part.

(9) ASME/ANSI MFC–7M–1987 (Reaffirmed 2006), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, IBR approved for § 60.107a(d) of subpart Ja of this part.

(10) ASME/ANSI MFC–9M–1988 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits by Weighing Method, IBR approved for § 60.107a(d) of subpart Ja of this part.

(11) ASME MFC–11M–2006, Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for § 60.107a(d) of subpart Ja of this part.

(12) ASME MFC–14M–2003, Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for § 60.107a(d) of subpart Ja of this part.

(13) ASME MFC–16–2007, Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters, IBR approved for § 60.107a(d) of subpart Ja of this part.

(14) ASME MFC–18M–2001, Measurement of Fluid Flow Using Variable Area Meters, IBR approved for § 60.107a(d) of subpart Ja of this part.

(15) ASME MFC–22–2007, Measurement of Liquid by Turbine Flowmeters, IBR approved for § 60.107a(d) of subpart Ja of this part.

* * * * *

(m) * * *

(2) Gas Processors Association Standard 2172–09, Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (2009), IBR approved for § 60.107a(d) of subpart Ja of this part.

(3) Gas Processors Association Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (2000), IBR approved for § 60.107a(d) of subpart Ja of this part.

* * * * *

(p) The following American Gas Association material is available for purchase from the following address: ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990), IBR approved for § 60.107a(d) of subpart Ja of this part.

(2) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 2: Specification and Installation Requirements (2000), IBR approved for § 60.107a(d) of subpart Ja of this part.

(3) American Gas Association Report No. 11: Measurement of Natural Gas by Coriolis Meter (2003), IBR approved for § 60.107a(d) of subpart Ja of this part.

(4) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Revised February 2006), IBR approved for § 60.107a(d) of subpart Ja of this part.

(q) The following material is available for purchase from the International Standards Organization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm.*

(1) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987–10–01)—First Edition, IBR approved for § 60.107a(d) of subpart Ja of this part.

(2) [Reserved]

Subpart J—[AMENDED]

■ 5. Section 60.100 is amended by:

■ a. Revising paragraph (b);

■ b. Redesignating paragraph (e) as (f); and

■ c. Adding a new paragraph (e) to read as follows:

§ 60.100 Applicability, designation of affected facility, and reconstruction.

* * * * *

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section other than a flare which commences construction, reconstruction or modification after June 11, 1973, and on or before May 14, 2007, or any fuel gas combustion device under paragraph (a) of this section that is also a flare which commences construction, reconstruction or modification after June 11, 1973, and on or before June 24, 2008, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction, reconstruction or modification after October 4, 1976, and on or before May 14, 2007, is subject to the requirements of this subpart except as provided under paragraphs (c) through (e) of this section.

* * * * *

(e) Owners or operators may choose to comply with the applicable provisions of subpart Ja of this part to satisfy the requirements of this subpart for an affected facility.

* * * * *

■ 6. Section 60.101 is amended by revising paragraph (d) to read as follows:

§ 60.101 Definitions.

* * * * *

(d) *Fuel gas* means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. Fuel gas does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units or marine tank vessel loading operations.

* * * * *

■ 7. Section 60.106 is amended by revising paragraph (c)(1) to read as follows:

§ 60.106 Test methods and procedures.

* * * * *

(c) * * *

(1) The allowable emission rate (E_s) of PM shall be computed for each run using the following equation:

$$E_s = F + A\,(H/R_c)$$

Where:

E_s = Emission rate of PM allowed, kg/Mg (lb/ton) of coke burn-off in catalyst regenerator.

F = Emission standard, 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in catalyst regenerator.

A = Allowable incremental rate of PM emissions, 43 g/GJ (0.10 lb/million Btu).

H = Heat input rate from solid or liquid fossil fuel, GJ/hr (million Btu/hr).

R_c = Coke burn-off rate, Mg coke/hr (ton coke/hr).

* * * * *

Subpart Ja—[AMENDED]

■ 7. In § 60.100a, lift the stay on paragraph (c) published December 22, 2008 (73 FR 78552).

■ 8. Section 60.100a is amended by:
■ a. Revising paragraph (a);
■ b. Revising paragraph (b);
■ c. Revising paragraph (c) introductory text and paragraph (c)(1); and
■ d. Revising paragraph (d).

The revisions read as follows:

§ 60.100a Applicability, designation of affected facility, and reconstruction.

(a) The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants. The sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(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 commence construction, modification or reconstruction after May 14, 2007. For flares, the provisions of this subpart apply only to flares which commence construction, modification or reconstruction after June 24, 2008. For the purposes of this subpart, a modification to a flare commences when a project that includes any of the activities in paragraphs (c)(1) or (2) of this section is commenced. For delayed coking units, the provisions of this subpart apply to delayed coking units that commence construction, reconstruction or modification on the earliest of the following dates:

(1) May 14, 2007, for such activities that involve a ''delayed coking unit'' defined as follows: one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors;

(2) December 22, 2008, for such activities that involve a ''delayed coking unit'' defined as follows: 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 consists of the coke drums and associated fractionator;

(3) September 12, 2012, for such activities that involve a ''delayed coking unit'' as defined in § 60.101a.

(c) For all affected facilities other than flares, the provisions in § 60.14 regarding modification apply. As provided in § 60.14(f), the special provisions set forth under this subpart shall supersede the provisions in § 60.14 with respect to flares. For the purposes of this subpart, a modification to a flare occurs as provided in paragraphs (c)(1) or (2) of this section.

(1) Any new piping from a refinery process unit, including ancillary equipment, or a fuel gas system is physically connected to the flare (*e.g.,* for direct emergency relief or some form of continuous or intermittent venting). However, the connections described in paragraphs (c)(1)(i) through (vii) of this section are not considered modifications of a flare.

(i) Connections made to install monitoring systems to the flare.

(ii) Connections made to install a flare gas recovery system or connections made to upgrade or enhance components of a flare gas recovery system (*e.g.,* addition of compressors or recycle lines).

(iii) Connections made to replace or upgrade existing pressure relief or safety valves, provided the new pressure relief or safety valve has a set point opening pressure no lower and an internal diameter no greater than the existing equipment being replaced or upgraded.

(iv) Connections made for flare gas sulfur removal.

(v) Connections made to install back-up (redundant) equipment associated with the flare (such as a back-up compressor) that does not increase the capacity of the flare.

(vi) Replacing piping or moving an existing connection from a refinery process unit to a new location in the same flare, provided the new pipe diameter is less than or equal to the diameter of the pipe/connection being replaced/moved.

(vii) Connections that interconnect two or more flares.

* * * * *

(d) For purposes of this subpart, under § 60.15, the ''fixed capital cost of the new components'' includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the relevant applicability date specified in paragraph (b) of this section.

■ 9. In § 60.101a, lift the stay on the definition of ''flare'' published December 22, 2008 (73 FR 78552).

■ 10. Section 60.101a is amended by:
■ a. Revising the introductory text;
■ b. Adding, in alphabetical order, definitions of ''Air preheat,'' ''Ancillary equipment,'' ''Cascaded flare system,'' ''Co-fired process heater,'' ''Corrective action,'' ''Corrective action analysis,'' ''Emergency flare,'' ''Flare gas header system,'' ''Flare gas recovery system,'' ''Forced draft process heater,'' ''Natural draft process heater,'' ''Non-emergency flare,'' ''Primary flare,'' ''Purge gas,'' ''Root cause analysis,'' ''Secondary flare,'' and ''Sweep gas''; and
■ c. Revising the definitions of ''Delayed coking unit,'' ''Flare,'' ''Flexicoking unit,'' ''Fluid coking unit,'' ''Fuel gas,'' ''Fuel gas combustion device,'' ''Petroleum refinery,'' ''Process upset gas'' and ''Sulfur recovery plant''

The revisions and additions read as follows:

§ 60.101a Definitions.

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 60.2 and in this section.

Air preheat means a device used to heat the air supplied to a process heater generally by use of a heat exchanger to recover the sensible heat of exhaust gas from the process heater.

Ancillary equipment means equipment used in conjunction with or that serve a refinery process unit. *Ancillary equipment* includes, but is not limited to, storage tanks, product loading operations, wastewater treatment systems, steam- or electricity-producing units (including coke gasification units), pressure relief valves, pumps, sampling vents and continuous analyzer vents.

Cascaded flare system means a series of flares connected to one flare gas header system arranged with increasing pressure set points so that discharges will be initially directed to the first flare in the series (*i.e.,* the primary flare). If the discharge pressure exceeds a set point at which the flow to the primary flare would exceed the primary flare's capacity, flow will be diverted to the second flare in the series. Similarly, flow would be diverted to a third (or fourth) flare if the pressure in the flare gas header system exceeds a threshold where the flow to the first two (or three) flares would exceed their capacities.

Co-fired process heater means a process heater that employs burners that are designed to be supplied by both gaseous and liquid fuels on a routine basis. Process heaters that have gas burners with emergency oil back-up burners are not considered co-fired process heaters.

* * * * *

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 to an affected flare in excess of specified thresholds.

Corrective action analysis means a description of all reasonable interim and long-term measures, if any, that are available, and an explanation of why the selected corrective action(s) is/are the best alternative(s), including, but not limited to, considerations of cost effectiveness, technical feasibility, safety and secondary impacts.

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; process piping and associated equipment such as pumps, valves and connectors; and the coke drum blowdown recovery compressor system.

Emergency flare means a flare that combusts gas exclusively released as a result of malfunctions (and not startup, shutdown, routine operations or any other cause) on four or fewer occasions in a rolling 365-day period. For purposes of this rule, a flare cannot be categorized as an *emergency flare* unless it maintains a water seal.

Flare means a combustion device that uses an uncontrolled volume of air to burn gases. The *flare* includes the foundation, flare tip, structural support, burner, igniter, flare controls, including air injection or steam injection systems, flame arrestors and the flare gas header system. In the case of an interconnected flare gas header system, the *flare* includes each individual flare serviced by the interconnected flare gas header system and the interconnected flare gas header system.

Flare gas header system means all piping and knockout pots, including those in a subheader system, used to collect and transport gas to a flare either from a process unit or a pressure relief valve from the fuel gas system, regardless of whether or not a flare gas recovery system draws gas from the *flare gas header system.* The *flare gas header system* includes piping inside the battery limit of a process unit if the purpose of the piping is to transport gas to a flare or knockout pot that is part of the flare.

Flare gas recovery system means a system of one or more compressors, piping and the associated water seal, rupture disk or similar device used to divert gas from the flare and direct the gas to the fuel gas system or to a fuel gas combustion device.

Flexicoking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced and then gasified to produce a synthetic fuel gas.

* * * * *

Fluid coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The *fluid coking unit* includes the coking reactor, the coking burner, and equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent.

Forced draft process heater means a process heater in which the combustion air is supplied under positive pressure produced by a fan at any location in the inlet air line prior to the point where the combustion air enters the process heater or air preheat. For the purposes of this subpart, a process heater that uses fans at both the inlet air side and the exhaust air side (*i.e.,* balanced draft system) is considered to be a *forced draft process heater.*

Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. *Fuel gas* includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. *Fuel gas* does not include gases generated by catalytic cracking unit catalyst regenerators, coke calciners (used to make premium grade coke) and fluid coking burners, but does include gases from flexicoking unit gasifiers and other gasifiers. *Fuel gas* does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations or asphalt processing units (*i.e.,* asphalt blowing stills).

Fuel gas combustion device means any equipment, such as process heaters and boilers, used to combust fuel gas. For the purposes of this subpart, *fuel gas combustion device* does not include flares or facilities in which gases are combusted to produce sulfur or sulfuric acid.

* * * * *

Natural draft process heater means any process heater in which the combustion air is supplied under ambient or negative pressure without the use of an inlet air (forced draft) fan. For the purposes of this subpart, a *natural draft process heater* is any process heater that is not a forced draft process heater, including induced draft systems.

Non-emergency flare means any flare that is not an emergency flare as defined in this subpart.

* * * * *

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives. A facility that produces only oil shale or tar sands-derived crude oil for further processing at a petroleum refinery using only solvent extraction and/or distillation to recover diluent is not a *petroleum refinery.*

Primary flare means the first flare in a cascaded flare system.

* * * * *

Process upset gas means any gas generated by a petroleum refinery process unit or by ancillary equipment as a result of startup, shutdown, upset or malfunction.

Purge gas means gas introduced between a flare's water seal and a flare's tip to prevent oxygen infiltration (backflow) into the flare tip. For flares with no water seals, the function of *purge gas* is performed by sweep gas (*i.e.,* flares without water seals do not use *purge gas*).

* * * * *

Root cause analysis means an assessment conducted through a process of investigation to determine the primary cause, and any other contributing cause(s), of a discharge of gases in excess of specified thresholds.

Secondary flare means a flare in a cascaded flare system that provides additional flare capacity and pressure relief to a flare gas system when the flare gas flow exceeds the capacity of the primary flare. For purposes of this subpart, a *secondary flare* is characterized by infrequent use and must maintain a water seal.

* * * * *

Sulfur recovery plant means all process units which recover sulfur from H_2S and/or SO_2 from a common source of sour gas produced at a petroleum refinery. The *sulfur recovery plant* also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels or loading facilities downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits and, if present, oxidation or reduction control systems or incinerator, thermal oxidizer or similar combustion device. Multiple sulfur recovery units are a single affected facility only when the units share the same source of sour gas. *Sulfur recovery plants* that receive source gas from completely segregated sour gas treatment systems are separate affected facilities.

Sweep gas means the gas introduced in a flare gas header system to maintain a constant flow of gas to prevent oxygen buildup in the flare header. For flares with no water seals, *sweep gas* also performs the function of preventing oxygen infiltration (backflow) into the flare tip.

■ 11. In § 60.102a, lift the stay on paragraph (g) published December 22, 2008 (73 FR 78552).

■ 12. Section 60.102a is amended by:
■ a. Revising paragraph (a);
■ b. Revising paragraph (f)(1)(ii);
■ c. Revising paragraph (g);
■ d. Removing and reserving paragraph (h); and
■ e. Revising paragraph (i).

The revisions read as follows:

§ 60.102a Emissions limitations.

(a) Each owner or operator that is subject to the requirements of this subpart shall comply with the emissions limitations in paragraphs (b) through (i) of this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated or 180 days after initial startup, whichever comes first.

* * * * *

(f) * * *

(1) * * *

(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 in excess of 300 ppmv of reduced sulfur compounds and 10 ppmv of H_2S, each calculated as ppmv SO_2 (dry basis) at 0-percent excess air; or

* * * * *

(g) Each owner or operator of an affected fuel gas combustion device shall comply with the emissions limits in paragraphs (g)(1) and (2) of this section.

(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.

(i) The owner or operator shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and SO_2 in excess of 8 ppmv (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis; or

(ii) The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(iii) The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in paragraphs (g)(1)(i) and (ii) of this section.

(2) For each process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr) on a higher heating value basis, the owner or operator shall not discharge to the atmosphere any emissions of NO_X in excess of the applicable limits in paragraphs (g)(2)(i) through (iv) of this section.

(i) For each natural draft process heater, comply with the limit in either paragraph (g)(2)(i)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in § 60.107a; if fuel gas composition is not monitored as specified in § 60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(i)(A) of this section.

(A) 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.040 pounds per million British thermal units (lb/MMBtu) higher heating value basis determined daily on a 30-day rolling average basis.

(ii) For each forced draft process heater, comply with the limit in either paragraph (g)(2)(ii)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in § 60.107a; if fuel gas composition is not monitored as specified in § 60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(ii)(A) of this section.

(A) 60 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.060 lb/MMBtu higher heating value basis determined daily on a 30-day rolling average basis.

(iii) For each co-fired natural draft process heater, comply with the limit in either paragraph (g)(2)(iii)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 3 of this section:

$$ER_{NOx} = \frac{0.06\,Q_{gas}\,HHV_{gas} + 0.35\,Q_{oil}\,HHV_{oil}}{Q_{gas}\,HHV_{gas} + Q_{oil}\,HHV_{oil}} \qquad \text{(Eq. 3)}$$

Where:

ER_{NOx} = Daily allowable average emission rate of NO_X, lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, standard cubic feet per day (scf/day);

Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/day;

HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and

HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

(iv) For each co-fired forced draft process heater, comply with the limit in either paragraph (g)(2)(iv)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 4 of this section:

$$ER_{NOx} = \frac{0.11 Q_{gas} HHV_{gas} + 0.40 Q_{oil} HHV_{oil}}{Q_{gas} HHV_{gas} + Q_{oil} HHV_{oil}} \qquad \text{(Eq. 4)}$$

Where:

ER_{NOx} = Daily allowable average emission rate of NO_X, lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, scf/day;

Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/day;

HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and

HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

(h) [Reserved]

(i) For a process heater that meets any of the criteria of paragraphs (i)(1)(i) through (iv) of this section, an owner or operator may request approval from the Administrator for a NO_X emissions limit which shall apply specifically to that affected facility. The request shall include information as described in paragraph (i)(2) of this section. The request shall be submitted and followed as described in paragraph (i)(3) of this section.

(1) A process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may apply for a site-specific NO_X emissions limit:

(i) A modified or reconstructed process heater that lacks sufficient space to accommodate installation and proper operation of combustion modification-based technology (*e.g.,* ultra-low NO_X burners); or

(ii) A modified or reconstructed process heater that has downwardly firing induced draft burners; or

(iii) A co-fired process heater; or

(iv) A process heater operating at reduced firing conditions for an extended period of time (*i.e.,* operating in turndown mode). The site-specific NO_X emissions limit will only apply for those operating conditions.

(2) The request shall include sufficient and appropriate data, as determined by the Administrator, to allow the Administrator to confirm that the process heater is unable to comply with the applicable NO_X emissions limit in paragraph (g)(2) of this section. At a minimum, the request shall contain the information described in paragraphs (i)(2)(i) through (iv) of this section.

(i) The design and dimensions of the process heater, evaluation of available combustion modification-based technology, description of fuel gas and, if applicable, fuel oil characteristics, information regarding the combustion conditions (temperature, oxygen content, firing rates) and other information needed to demonstrate that the process heater meets one of the four classes of process heaters listed in paragraph (i)(1) of this section.

(ii) An explanation of how the data in paragraph (i)(2)(i) demonstrate that ultra-low NO_X burners, flue gas recirculation, control of excess air or other combustion modification-based technology (including combinations of these combustion modification-based technologies) cannot be used to meet the applicable emissions limit in paragraph (g)(2) of this section.

(iii) Results of a performance test conducted under representative conditions using the applicable methods specified in § 60.104a(i) to demonstrate the performance of the technology the owner or operator will use to minimize NO_X emissions.

(iv) The means by which the owner or operator will document continuous compliance with the site-specific emissions limit.

(3) The request shall be submitted and followed as described in paragraphs (i)(3)(i) through (iii) of this section.

(i) The owner or operator of a process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may request approval from the Administrator within 180 days after initial startup of the process heater for a NO_X emissions limit which shall apply specifically to that affected facility.

(ii) The request must be submitted to the Administrator for approval. The owner or operator must comply with the request as submitted until it is approved.

(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 *refinerynsps@epa.gov.*

(4) The approval process for a request for a facility-specific NO_X emissions limit is described in paragraphs (i)(4)(i) through (iii) of this section.

(i) Approval by the Administrator of a facility-specific NO_X emissions limit 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, the following:

(A) A demonstration that the process heater meets one of the four classes of process heaters outlined in paragraphs (i)(1) of this section;

(B) A description of the low-NO_X burner designs and other combustion modifications considered for reducing NO_X emissions;

(C) The combustion modification option selected; and

(D) The operating conditions (firing rate, heater box temperature and excess oxygen concentration) at which the NO_X emission level was established.

(ii) If the request is approved by the Administrator, a facility-specific NO_X emissions limit will be established at the NO_X emission level 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.

■ 13. Section 60.103a is revised to read as follows:

§ 60.103a Design, equipment, work practice or operational standards.

(a) Except as provided in paragraph (g) of this section, each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management plan no later than the date specified in paragraph (b) of this section. The flare management plan must include the information described in paragraphs (a)(1) through (7) of this section.

(1) A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare.

(2) An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized. The flare minimization assessment must (at a minimum) consider the items in paragraphs (a)(2)(i) through (iv) 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.

(i) Elimination of process gas discharge to the flare through process operating changes or gas recovery at the source.

(ii) Reduction of the volume of process gas to the flare through process operating changes.

(iii) 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.

(iv) Minimization of sweep gas flow rates and, for flares with water seals, purge gas flow rates.

(3) A description of each affected flare containing the information in paragraphs (a)(3)(i) through (vii) of this section.

(i) A general description of the flare, including the information in paragraphs (a)(3)(i)(A) through (G) of this section.

(A) Whether it is a ground flare or elevated (including height).

(B) The type of assist system (*e.g.,* air, steam, pressure, non-assisted).

(C) Whether it is simple or complex flare tip (*e.g.,* staged, sequential).

(D) Whether the flare is part of a cascaded flare system (and if so, whether the flare is primary or secondary).

(E) Whether the flare serves as a backup to another flare.

(F) Whether the flare is an emergency flare or a non-emergency flare.

(G) Whether the flare is equipped with a flare gas recovery system.

(ii) Description and simple process flow diagram showing the interconnection of the 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.

(iii) Flare design parameters, including the maximum vent gas flow rate; minimum sweep gas flow rate; minimum purge gas flow rate (if any); maximum supplemental gas flow rate; maximum pilot gas flow rate; and, if the flare is steam-assisted, minimum total steam rate.

(iv) Description and simple process flow diagram showing all gas lines (including flare, purge (if applicable), sweep, supplemental and pilot gas) that are associated with the flare. For purge, sweep, supplemental and pilot gas, identify the type of gas used. Designate which lines are exempt from sulfur, H_2S or flow monitoring and why (*e.g.,* natural gas, inherently low sulfur, pilot gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor.

(v) For each flow rate, H_2S, sulfur content, pressure or water seal monitor identified in paragraph (a)(3)(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 emergency flares, secondary flares and flares equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction:

(A) Description of the water seal, including the operating range for the liquid level.

(B) Designation of the monitoring option elected (flow and sulfur monitoring or pressure and water seal liquid level monitoring).

(vii) For flares equipped with a flare gas recovery system:

(A) A description of the flare gas recovery system, including number of compressors and capacity of each compressor.

(B) A description of the monitoring parameters used to quantify the amount of flare gas recovered.

(C) For systems with staged compressors, the maximum time period required to begin gas recovery with the secondary compressor(s), the monitoring parameters and procedures used to minimize the duration of releases during compressor staging and a justification for why the maximum time period cannot be further reduced.

(4) An evaluation of the baseline flow to the flare. The baseline flow to the flare must be determined after implementing the minimization assessment in paragraph (a)(2) of this section. Baseline flows do not include pilot gas flow or purge gas flow (*i.e.,* gas introduced after the flare's water seal) provided these gas flows remain reasonably constant (*i.e.,* separate flow monitors for these streams are not required). Separate baseline flow rates may be established for different operating conditions provided that the management plan includes:

(i) A primary baseline flow rate that will be used as the default baseline for all conditions except those specifically delineated in the plan;

(ii) A description of each special condition for which an alternate baseline is established, including the rationale for each alternate baseline, the daily flow for each alternate baseline and the expected duration of the special conditions for each alternate baseline; and

(iii) Procedures to minimize discharges to the affected flare during each special condition described in paragraph (a)(4)(ii) of this section, unless procedures are already developed for these cases under paragraph (a)(5) through (7) of this section, as applicable.

(5) 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.

(6) Procedures to reduce flaring in cases of fuel gas imbalance (*i.e.,* excess fuel gas for the refinery's energy needs), 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.

(7) For flares equipped with flare gas recovery systems, procedures to minimize the frequency and duration of outages of the flare gas recovery system and procedures to minimize the volume of gas flared during such outages, 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.

(b) Except as provided in paragraph (g) of this section, each owner or operator required to develop and implement a written flare management plan as described in paragraph (a) of this section must submit the plan to the Administrator as described in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator of a newly constructed or reconstructed flare must develop and implement the flare management plan by no later than the date that the flare becomes an affected facility subject to this subpart, except for the selected minimization alternatives in paragraph (a)(2) and/or the procedures in paragraphs (a)(5) though (a)(7) of this section that cannot reasonably be implemented by that date, which the owner or operator must implement in accordance with the schedule in the flare management plan. The owner or operator of a modified flare must develop and implement the flare management plan by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(2) The owner or operator must comply with the plan as submitted by the date specified in paragraph (b)(1) 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 adds an alternative baseline flow rate, revises an existing baseline as described in paragraph (a)(4) of this section, installs a flare gas recovery system or is required to change flare designations and monitoring methods as described in § 60.107a(g). The owner or operator must comply with the updated plan as submitted.

(3) 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 *refinerynsps@epa.gov*.

(c) Except as provided in paragraphs (f) and (g) of this section, each owner or operator that operates a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each of the conditions specified in paragraphs (c)(1) through (3) of this section.

(1) For a flare:

(i) Any time the SO_2 emissions exceed 227 kilograms (kg) (500 lb) in any 24-hour period; or

(ii) Any discharge to the flare in excess of 14,160 standard cubic meters (m^3) (500,000 standard cubic feet (scf)) above the baseline, determined in paragraph (a)(4) of this section, in any 24-hour period; or

(iii) If the monitoring alternative in § 60.107a(g) is elected, any period when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in paragraph (a)(3)(vii)(C) of this section.

(2) For a fuel gas combustion device, each exceedance of an applicable short-term emissions limit in § 60.102a(g)(1) if the SO_2 discharge to the atmosphere is 227 kg (500 lb) greater than the amount that would have been emitted if the emissions limits had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(3) For a sulfur recovery plant, each time the SO_2 emissions are more than 227 kg (500 lb) greater than the amount that would have been emitted if the SO_2 or reduced sulfur concentration was equal to the applicable emissions limit in § 60.102a(f)(1) or (2) during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(d) Except as provided in paragraphs (f) and (g) of this section, a root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified in paragraphs (c)(1) through (3) of this section. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (d)(1) through (5) of this section.

(1) If a single continuous discharge meets any of the conditions specified in paragraphs (c)(1) through (3) of this section for 2 or more consecutive 24-hour periods, a single root cause analysis and corrective action analysis may be conducted.

(2) If a single discharge from a flare triggers a root cause analysis based on more than one of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section, a single root cause analysis and corrective action analysis may be conducted.

(3) If the discharge from a flare is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare and the procedures in paragraph (a)(5) of this section were followed, a root cause analysis and corrective action analysis is not required; however, the discharge must be recorded as described in § 60.108a(c)(6) and reported as described in § 60.108a(d)(5).

(4) If both the primary and secondary flare in a cascaded flare system meet any of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section in the same 24-hour period, a single root cause analysis and corrective action analysis may be conducted.

(5) Except as provided in paragraph (d)(4) of this section, if discharges occur that meet any of the conditions specified in paragraphs (c)(1) through (3) of this section for more than one affected facility in the same 24-hour period, initial root cause analyses shall be conducted for each affected facility. If the initial root cause analyses indicate that the discharges have the same root cause(s), the initial root cause analyses can be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(e) Except as provided in paragraphs (f) and (g) of this section, each owner or operator of a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall implement the corrective action(s) identified in the corrective action analysis conducted pursuant to paragraph (d) of this section in accordance with the applicable requirements in paragraphs (e)(1) through (3) of this section.

(1) All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that corrective action should not be conducted, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in § 60.108a(c)(6)(ix).

(2) For corrective actions that cannot be fully implemented within 45 days following the discharge 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.

(3) No later than 45 days following the discharge 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 as specified in § 60.108a(c)(6)(x).

(f) Modified flares shall comply with the requirements of paragraphs (c) through (e) of this section by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were not affected facilities subject to subpart J of this part prior to becoming affected facilities under § 60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of § 60.107a(a)(2) by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were affected facilities subject to subpart J of this part prior to becoming affected facilities under § 60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of § 60.107a(a)(2) by November 13, 2012 or at startup of the modified flare, whichever is later, except that modified flares that have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree, but shall comply with the requirements of paragraph (h) of this section and the requirements of § 60.107a(a)(2) by no later than November 11, 2015.

(g) An affected flare subject to this subpart located in the Bay Area Air Quality Management District (BAAQMD) may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. An affected flare subject to this subpart located in the South Coast Air Quality Management District (SCAQMD) may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. The owner or operator of an affected flare must notify the Administrator that the flare is in compliance with BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 or SCAQMD Rule 1118. The owner or operator of an affected flare shall also submit the existing flare management plan 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 *refinerynsps@epa.gov.*

(h) Each owner or operator shall not burn in any affected flare any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit.

(i) Each owner or operator of a delayed coking unit shall depressure each coke drum to 5 lb per square inch gauge (psig) or less prior to discharging the coke drum steam exhaust to the atmosphere. Until the coke drum pressure reaches 5 psig, the coke drum steam exhaust must be managed in an enclosed blowdown system and the uncondensed vapor must either be recovered (*e.g.,* sent to the delayed coking unit fractionators) or vented to the fuel gas system, a fuel gas combustion device or a flare.

(j) *Alternative means of emission limitation.* (1) Each owner or operator subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant achieved by the controls required in this section.

(2) Determination of equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate the equivalence of the alternative means of emission limitation.

(ii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.

(iii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(iv) Each owner or operator applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(v) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in paragraph (j)(2)(iv) of this section.

(vi) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements.

(3) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(4) Approval of the application for equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) After a request for determination of equivalence is received, the Administrator will publish a notice in the **Federal Register** and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(ii) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the **Federal Register**.

(iii) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of section 111(h)(1) of the CAA.

(5) Manufacturers of equipment used to control emissions may apply to the Administrator for determination of equivalence for any alternative means of emission limitation that achieves a reduction in emissions achieved by the equipment, design and operational requirements of this section. The Administrator will make an equivalence determination according to the provisions of paragraphs (j)(2) through (4) of this section.

■ 14. Section 60.104a is amended by:
■ a. Revising paragraph (a);
■ b. Revising paragraphs (d)(4)(ii), (d)(4)(iii), (d)(4)(v) and (d)(8);
■ c. Revising paragraph (f)(3);
■ d. Revising paragraph (h)(5)(iv);
■ e. Revising paragraph (i) introductory text;
■ f. Adding paragraphs (i)(6) through (i)(8);
■ g. Revising paragraph (j) introductory text and paragraph (j)(4) introductory text; and
■ h. Revising paragraph (j)(4)(iv) to read as follows:

§ 60.104a Performance tests.

(a) The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant, flare and fuel gas combustion device to demonstrate initial compliance with each applicable emissions limit in § 60.102a according to the requirements of § 60.8. The notification requirements of § 60.8(d) apply to the initial performance test and to subsequent performance tests required by paragraph (b) of this section (or as required by the Administrator), but does not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments.

* * * * *

(d) * * *

(4) * * *

(ii) The emissions rate of PM (E_{PM}) is computed for each run using Equation 5 of this section:

$$E = \frac{c_s Q_{sd}}{K R_c} \qquad \text{(Eq. 5)}$$

Where:

E = Emission rate of PM, g/kg (lb/1,000 lb) of coke burn-off;

c_s = Concentration of total PM, grams per dry standard cubic meter (g/dscm) (gr/dscf);

Q_{sd} = Volumetric flow rate of effluent gas, dry standard cubic meters per hour (dry standard cubic feet per hour);

R_c = Coke burn-off rate, kilograms per hour (kg/hr) [lb per hour (lb/hr)] coke; and

K = Conversion factor, 1.0 grams per gram (7,000 grains per lb).

(iii) The coke burn-off rate (R_c) is computed for each run using Equation 6 of this section:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \left(\%CO/2 + \%CO_2 + \%O_2 \right) + K_3 Q_{oxy} (\%O_{oxy}) \qquad \text{(Eq. 6)}$$

Where:

R_c = Coke burn-off rate, kg/hr (lb/hr);

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emissions control or energy recovery system that burns auxiliary fuel, dry standard cubic meters per minute (dscm/min) [dry standard cubic feet per minute (dscf/min)];

Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O_2 enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide (CO_2) concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%CO = CO concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%O_2$ = O_2 concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the FCCU regenerator or fluid coking burner, 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)]; and

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

* * * * *

(v) For subsequent calculations of coke burn-off rates or exhaust gas flow rates, the volumetric flow rate of Q_r is calculated using average exhaust gas concentrations as measured by the monitors required in § 60.105a(b)(2), if applicable, using Equation 7 of this section:

$$Q_r = \frac{79 \times Q_a + (100 - \%Oxy) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. 7)}$$

Where:

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emission control or energy recovery system that burns auxiliary fuel, dscm/min (dscf/min);

Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O_2 enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%CO = CO concentration FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required in accordance with § 60.105a(h)(3), assume %CO to be zero;

$\%O_2$ = O_2 concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis); and

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis).

* * * * *

(8) The owner or operator shall adjust PM, NO_X, SO_2 and CO pollutant concentrations to 0-percent excess air or 0-percent O_2 using Equation 8 of this section:

$$C_{adj} = C_{meas}\left[20.9_c \Big/ \left(20.9 - \%O_2\right)\right] \qquad \texttt{(Eq. 8)}$$

Where:

C_{adj} = pollutant concentration adjusted to 0-percent excess air or O_2, parts per million (ppm) or g/dscm;

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm;

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.

* * * * *

(f) * * *

(3) Compute the site-specific limit using Equation 9 of this section:

$$Opacity\ \ Limit = Opacity_{st}\ x\left(\frac{1\,\mathrm{lb} / 1{,}000\ \mathrm{lb\ coke\ burn}}{PMEmR_{st}}\right) \qquad \texttt{(Eq. 9)}$$

Where:

Opacity limit = Maximum permissible 3-hour 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.

* * * * *

(h) * * *

(5) * * *

(iv) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O_2 or 0- percent excess air.

(i) The owner or operator shall determine compliance with the SO_2 and NO_X emissions limits in § 60.102a(g) for a fuel gas combustion device according to the following test methods and procedures:

* * * * *

(6) For process heaters with a rated heat capacity between 40 and 100 MMBtu/hr that elect to demonstrate continuous compliance with a maximum excess oxygen limit as provided in § 60.107a(c)(6) or (d)(8), the owner or operator shall establish the O_2 operating limit or O_2 operating curve based on the performance test results according to the requirements in paragraph (i)(6)(i) or (ii) of this section, respectively.

(i) If a single O_2 operating limit will be used:

(A) Conduct the performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section when the process heater is firing at no less than 70 percent of the rated heat capacity. For co-fired process heaters, conduct at least one of the test runs while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(B) Each test will consist of three test runs. Calculate the NO_X concentration for the performance test as the average of the NO_X concentrations from each of the three test runs. If the NO_X concentration for the performance test is less than or equal to the numerical value of the applicable NO_X emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) Determine the average O_2 concentration for each test run of a valid test.

(D) Calculate the O_2 operating limit as the average O_2 concentration of the three test runs from a valid test.

(ii) If an O_2 operating curve will be used:

(A) Conduct a performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section at a representative condition for each operating range for which different O_2 operating limits will be established. Different operating conditions may be defined as different firing rates (*e.g.,* above 50 percent of rated heat capacity and at or below 50 percent of rated heat capacity) and/or, for co-fired process heaters, different fuel mixtures (*e.g.,* primarily gas fired, primarily oil fired, and equally co-fired, *i.e.,* approximately 50 percent of the input heating value is from fuel gas and approximately 50 percent of the input heating value is from fuel oil). Performance tests for different operating ranges may be conducted at different times.

(B) Each test will consist of three test runs. Calculate the NO_X concentration for the performance test as the average of the NO_X concentrations from each of the three test runs. If the NO_X concentration for the performance test is less than or equal to the numerical value of the applicable NO_X emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) If an operating curve is developed for different firing rates, conduct at least one test when the process heater is firing at no less than 70 percent of the rated heat capacity and at least one test under turndown conditions (*i.e.,* when the process heater is firing at 50 percent or less of the rated heat capacity). If O_2 operating limits are developed for co-fired process heaters based only on overall firing rates (and not by fuel mixtures), conduct at least one of the test runs for each test while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(D) Determine the average O_2 concentration for each test run of a valid test.

(E) Calculate the O_2 operating limit for each operating range as the average O_2 concentration of the three test runs from a valid test conducted at the representative conditions for that given operating range.

(F) Identify the firing rates for which the different operating limits apply. If only two operating limits are established based on firing rates, the O_2 operating limits established when the process heater is firing at no less than 70 percent of the rated heat capacity must apply when the process heater is firing above 50 percent of the rated heat capacity and the O_2 operating limits established for turndown conditions must apply when the process heater is firing at 50 percent or less of the rated heat capacity.

(G) Operating limits associated with each interval will be valid for 2 years or until another operating limit is established for that interval based on a more recent performance test specific for that interval, whichever occurs first. Owners and operators must use the operating limits determined for a given interval based on the most recent performance test conducted for that interval.

(7) The owner or operator of a process heater complying with a NO_X limit in terms of lb/MMBtu as provided in § 60.102a(g)(2)(i)(B), (g)(2)(ii)(B), (g)(2)(iii)(B) or (g)(2)(iv)(B) or a process heater with a rated heat capacity between 40 and 100 MMBtu/hr that

elects to demonstrate continuous compliance with a maximum excess O_2 limit, as provided in § 60.107a(c)(6) or (d)(8), shall determine heat input to the process heater in MMBtu/hr during each performance test run by measuring fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in § 60.107a(d)(5), (d)(6), and (d)(4) or (d)(7), respectively.

(8) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O_2 or 0- percent excess air.

(j) The owner or operator shall determine compliance with the applicable H_2S emissions limit in § 60.102a(g)(1) for a fuel gas combustion device or the concentration requirement in § 60.103a(h) for a flare according to the following test methods and procedures:

* * * * *

(4) EPA Method 11, 15 or 15A of Appendix A–5 to part 60 or EPA Method 16 of Appendix A–6 to part 60 for determining the H_2S concentration for affected facilities using an H_2S monitor as specified in § 60.107a(a)(2). 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 part 60. The owner or operator may demonstrate compliance based on the mixture used in the fuel gas combustion device or flare or for each individual fuel gas stream used in the fuel gas combustion device or flare.

* * * * *

(iv) If monitoring is conducted at a single point in a common source of fuel gas as allowed under § 60.107a(a)(2)(iv), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device or flare is added to a common source of fuel gas that previously demonstrated compliance.

■ 15. Section 60.105a is amended by:

■ a. Revising paragraph (b) introductory text, and paragraph (b)(1) introductory text, and paragraphs (b)(1)(ii)(A), (b)(2)(i) and (b)(2)(ii); and

■ b. Revising paragraph (i)(5) to read as follows:

§ 60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).

* * * * *

(b) *Control device operating parameters.* Each owner or operator of a FCCU or FCU subject to the PM per coke burn-off emissions limit in § 60.102a(b)(1) that uses a control device other than fabric filter or cyclone shall comply with the requirements in paragraphs (b)(1) and (2) of this section.

(1) The owner or operator shall install, operate and maintain continuous parameter monitor systems (CPMS) to measure and record operating parameters for each control device according to the applicable requirements in paragraphs (b)(1)(i) through (v) of this section.

* * * * *

(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.

* * * * *

(2) * * *

(i) The owner or operator shall install, operate and maintain each monitor according to Performance Specifications 3 and 4 of Appendix B to part 60.

(ii) The owner or operator shall conduct performance evaluations of each CO_2, O_2 and CO monitor according to the requirements in § 60.13(c) and Performance Specifications 3 and 4 of Appendix B to part 60. The owner or operator shall use EPA Method 3 of Appendix A–3 to part 60 and EPA Method 10, 10A or 10B of Appendix A–4 to part 60 for conducting the relative accuracy evaluations.

* * * * *

(i) * * *

(5) All rolling 7-day periods during which the average concentration of SO_2 as measured by the SO_2 CEMS under § 60.105a(g) exceeds 50 ppmv, and all rolling 365-day periods during which the average concentration of SO_2 as measured by the SO_2 CEMS exceeds 25 ppmv.

* * * * *

■ 16. In § 60.107a, lift the stay on paragraphs (d) and (e) published December 22, 2008 (73 FR 78552).

■ 17. Section 60.107a is amended by:

■ a. Revising the section heading;

■ b. Revising paragraph (a) introductory text, paragraph (a)(1) introductory text, paragraph (a)(2) introductory text, (a)(2)(i), (a)(2)(iv) and paragraph (a)(3) introductory text;

■ c. Adding paragraphs (a)(2)(v) and (a)(2)(vi);

■ d. Revising paragraph (b) introductory text and paragraphs (b)(1)(i), (b)(1)(v) and (b)(3)(iii);

■ e. Revising paragraph (c) introductory text and paragraphs (c)(1) and (c)(6);

■ f. Redesignating paragraphs (d), (e), and (f) as paragraphs (e), (f) and (i), respectively;

■ g. Adding a new paragraph (d);

■ h. Revising newly redesignated paragraph (e);

■ i. Revising newly redesignated paragraph (f);

■ j. Adding a new paragraph (g);

■ k. Adding a new paragraph (h); and

■ l. Revising newly redesignated paragraph (i).

The revisions and additions read as follows:

§ 60.107a Monitoring of emissions and operations for fuel gas combustion devices and flares.

(a) *Fuel gas combustion devices subject to* SO_2 or H_2S limit and flares subject to H_2S concentration requirements. The owner or operator of a fuel gas combustion device that is subject to § 60.102a(g)(1) and elects to comply with the SO_2 emission limits in § 60.102a(g)(1)(i) shall comply with the requirements in paragraph (a)(1) of this section. The owner or operator of a fuel gas combustion device that is subject to § 60.102a(g)(1) and elects to comply with the H_2S concentration limits in § 60.102a(g)(1)(ii) or a flare that is subject to the H_2S concentration requirement in § 60.103a(h) shall comply with paragraph (a)(2) of this section.

(1) The owner or operator of a fuel gas combustion device that elects to comply with the SO_2 emissions limits in § 60.102a(g)(1)(i) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of SO_2 emissions into the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air.

* * * * *

(2) The owner or operator of a fuel gas combustion device that elects to comply with the H_2S concentration limits in § 60.102a(g)(1)(ii) or a flare that is subject to the H_2S concentration requirement in § 60.103a(h) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases before being burned in any fuel gas combustion device or flare.

(i) The owner or operator shall install, operate and maintain each H_2S monitor according to Performance Specification 7 of Appendix B to part 60. The span value for this instrument is 300 ppmv H_2S.

* * * * *

(iv) Fuel gas combustion devices or flares having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned in the respective fuel gas combustion devices or flares.

(v) The owner or operator of a flare subject to § 60.103a(c) through (e) may use the instrument required in paragraph (e)(1) of this section to demonstrate compliance with the H_2S concentration requirement in § 60.103a(h) if the owner or operator complies with the requirements of paragraph (e)(1)(i) through (iv) and if the instrument has a span (or dual span, if necessary) capable of accurately measuring concentrations between 20 and 300 ppmv. If the instrument required in paragraph (e)(1) of this section is used to demonstrate compliance with the H_2S concentration requirement, the concentration directly measured by the instrument must meet the numeric concentration in § 60.103a(h).

(vi) The owner or operator of modified flare that meets all three criteria in paragraphs (a)(2)(vi)(A) through (C) of this section shall comply with the requirements of paragraphs (a)(2)(i) through (v) of this section no later than November 11, 2015. The owner or operator shall comply with the approved alternative monitoring plan or plans pursuant to § 60.13(i) until the flare is in compliance with requirements of paragraphs (a)(2)(i) through (v) of this section.

(A) The flare was an affected facility subject to subpart J of this part prior to becoming an affected facility under § 60.100a.

(B) The owner or operator had an approved alternative monitoring plan or plans pursuant to § 60.13(i) for all fuel gases combusted in the flare.

(C) The flare did not have in place on or before September 12, 2012 an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases that is capable of complying with the requirements of paragraphs (a)(2)(i) through (v) of this section.

(3) The owner or operator of a fuel gas combustion device or flare is not required to comply with paragraph (a)(1) or (2) of this section for fuel gas streams that are exempt under §§ 60.102a(g)(1)(iii) or 60.103a(h) or, for fuel gas streams combusted in a process heater, other fuel gas combustion device or flare that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(3)(i) through (iv) of this section will be considered inherently low in sulfur content.

* * * * *

(b) *Exemption from H_2S monitoring requirements for low-sulfur fuel gas streams.* The owner or operator of a fuel gas combustion device or flare may apply for an exemption from the H_2S monitoring requirements in paragraph (a)(2) of this section for a fuel gas stream that is inherently low in sulfur content. A fuel gas stream that is demonstrated to be low-sulfur is exempt from the monitoring requirements of paragraphs (a)(1) and (2) of this section until there are changes in operating conditions or stream composition.

(1) * * *

(i) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system and the affected fuel gas combustion device(s) or flare(s) to be considered;

* * * * *

(v) A description of how the 2 weeks (or seven samples for infrequently operated fuel gas streams/systems) of monitoring results compares to the typical range of H_2S concentration (fuel quality) expected for the fuel gas stream/system going to the affected fuel gas combustion device or flare (*e.g.,* the 2 weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out and, therefore, should be representative of typical operating conditions affecting H_2S content in the fuel gas stream going to the loading rack flare).

* * * * *

(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. The owner or operator must begin monitoring according to the requirements in paragraphs (a)(1) or (a)(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. The owner or operator of a fuel gas combustion device must also determine a rolling 365-day average using the stain sampling results; an average H_2S concentration of 5 ppmv must be used for days within the rolling 365-day period prior to the operation change.

(c) *Process heaters complying with the NO_X concentration-based limit.* The owner or operator of a process heater subject to the NO_X emissions limit in § 60.102a(g)(2) and electing to comply with the applicable emissions limit in § 60.102a(g)(2)(i)(A), (g)(2)(ii)(A), (g)(2)(iii)(A) or (g)(2)(iv)(A) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere according to the requirements in paragraphs (c)(1) through (5) of this section, except as provided in paragraph (c)(6) of this section. The monitor must include an O_2 monitor for correcting the data for excess air.

(1) Except as provided in paragraph (c)(6) of this section, the owner or operator shall install, operate and maintain each NO_X monitor according to Performance Specification 2 of Appendix B to part 60. The span value of this NO_X monitor must be between 2 and 3 times the applicable emissions limit, inclusive.

* * * * *

(6) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification-based technology to reduce NO_X emissions (*i.e.,* low-NO_X burners, ultra-low-NO_X burners) may elect to comply with the monitoring requirements in paragraphs (c)(1) through (5) of this section or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests according to the requirements in § 60.104a(i), establish a maximum excess O_2 operating limit or operating curve according to the requirements in § 60.104a(i)(6) and comply with the O_2 monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance. If an O_2 operating curve is used (*i.e.,* if different O_2 operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of this section, respectively.

(d) *Process heaters complying with the NO_X heating value-based or mass-based limit.* The owner or operator of a process heater subject to the NO_X emissions limit in § 60.102a(g)(2) and electing to comply with the applicable emissions limit in § 60.102a(g)(2)(i)(B) or (g)(2)(ii)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere and shall determine the F factor of the fuel gas stream no less frequently than once per day according to the monitoring requirements in paragraphs (d)(1) through (4) of this section. The owner or operator of a co-fired process heater subject to the NO_X emissions limit in § 60.102a(g)(2) and electing to comply with the heating value-based limit in § 60.102a(g)(2)(iii)(B) or (g)(2)(iv)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere according to the monitoring requirements in paragraph (d)(1) of this section; install, operate, calibrate and maintain an instrument for continuously monitoring and recording the flow rate of the fuel gas and fuel oil fed to the process heater according to the monitoring requirements in paragraph (d)(5) and (6) of this section; for fuel gas streams, determine gas composition according to the requirements in paragraph (d)(4) of this section or the higher heating value according to the requirements in paragraph (d)(7) of this section; and for fuel oil streams, determine the heating value according to the monitoring requirements in paragraph (d)(7) of this section.

(1) Except as provided in paragraph (d)(8) of this section, the owner or operator shall install, operate and maintain each NO_X monitor according to the requirements in paragraphs (c)(1) through (5) of this section. The monitor must include an O_2 monitor for correcting the data for excess air.

(2) Except as provided in paragraph (d)(3) of this section, the owner or operator shall sample and analyze each fuel stream fed to the process heater using the methods and equations in section 12.3.2 of EPA Method 19 of Appendix A–7 to part 60 to determine the F factor on a dry basis. 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).

(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 10 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).

$$F_d = \frac{1{,}000{,}000 \times \sum\left(X_i \times MEV_i\right)}{\sum\left(X_i \times MHC_i\right)} \qquad \text{(Eq. 10)}$$

Where:

F_d = F factor on dry basis at 0-percent 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.

(4) The owner or operator shall conduct performance evaluations of each compositional monitor according to the requirements in Performance Specification 9 of Appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) EPA Method 18 of Appendix A–6 to part 60;

(ii) ASTM D1945–03 (Reapproved 2010)(incorporated by reference-see § 60.17);

(iii) ASTM D1946–90 (Reapproved 2006)(incorporated by reference-see § 60.17);

(iv) ASTM D6420–99 (Reapproved 2004)(incorporated by reference-see § 60.17);

(v) GPA 2261–00 (incorporated by reference-see § 60.17); or

(vi) ASTM UOP539–97 (incorporated by reference-see § 60.17).

(5) The owner or operator shall install, operate and maintain fuel gas flow monitors according to the manufacturer's recommendations. For volumetric flow meters, temperature and pressure monitors must be installed in conjunction with the flow meter or in a representative location to correct the measured flow to standard conditions (*i.e.,* 68 °F and 1 atmosphere). For mass flow meters, use gas compositions determined according to paragraph (d)(4) of this section to determine the average molecular weight of the fuel gas and convert the mass flow to a volumetric flow at standard conditions (*i.e.,* 68 °F and 1 atmosphere). The owner or operator shall conduct performance evaluations of each fuel gas flow monitor according to the requirements in § 60.13 and Performance Specification 6 of Appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) EPA Method 2, 2A, 2B, 2C or 2D of Appendix A–2 to part 60;

(ii) ASME MFC–3M–2004 (incorporated by reference-see § 60.17);

(iii) ANSI/ASME MFC–4M–1986 (Reaffirmed 2008) (incorporated by reference-see § 60.17);

(iv) ASME MFC–6M–1998 (Reaffirmed 2005) (incorporated by reference-see § 60.17);

(v) ASME/ANSI MFC–7M–1987 (Reaffirmed 2006) (incorporated by reference-see § 60.17);

(vi) ASME MFC–11M–2006 (incorporated by reference-see § 60.17);

(vii) ASME MFC–14M–2003 (incorporated by reference-see § 60.17);

(viii) ASME MFC–18M–2001 (incorporated by reference-see § 60.17);

(ix) AGA Report No. 3, Part 1 (incorporated by reference-see § 60.17);

(x) AGA Report No. 3, Part 2 (incorporated by reference-see § 60.17);

(xi) AGA Report No. 11 (incorporated by reference-see § 60.17);

(xii) AGA Report No. 7 (incorporated by reference-see § 60.17); and

(xiii) API Manual of Petroleum Measurement Standards, Chapter 22, Section 2 (incorporated by reference-see § 60.17).

(6) The owner or operator shall install, operate and maintain each fuel oil flow monitor according to the manufacturer's recommendations. The owner or operator shall conduct performance evaluations of each fuel oil flow monitor according to the requirements in § 60.13 and Performance Specification 6 of Appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) Any one of the methods listed in paragraph (d)(5) of this section that are applicable to fuel oil (*i.e.,* ''fluids'');

(ii) ANSI/ASME–MFC–5M–1985 (Reaffirmed 2006) (incorporated by reference-see § 60.17);

(iii) ASME/ANSI MFC–9M–1988 (Reaffirmed 2006) (incorporated by reference-see § 60.17);

(iv) ASME MFC–16–2007 (incorporated by reference-see § 60.17);

(v) ASME MFC–22–2007 (incorporated by reference-see § 60.17); or

(vi) ISO 8316 (incorporated by reference-see § 60.17).

(7) The owner or operator shall determine the higher heating value of each fuel fed to the process heater using any of the applicable methods included in paragraphs (d)(7)(i) through (ix) of this section. If a common fuel supply system provides fuel gas or fuel oil to several process heaters, the higher heating value of the fuel in each fuel supply system may be determined at a single location in the fuel supply system provided it is representative of the fuel fed to the affected process heater(s). The higher heating value of each fuel fed to the process heater must be determined no less frequently than once per day except as provided in paragraph (d)(7)(x) of this section.

(i) ASTM D240–02 (Reapproved 2007) (incorporated by reference-see § 60.17).

(ii) ASTM D1826–94 (Reapproved 2003) (incorporated by reference-see § 60.17).

(iii) ASTM D1945–03 (Reapproved 2010) (incorporated by reference-see § 60.17).

(iv) ASTM D1946–90 (Reapproved 2006) (incorporated by reference-see § 60.17).

(v) ASTM D3588–98 (Reapproved 2003) (incorporated by reference-see § 60.17).

(vi) ASTM D4809–06 (incorporated by reference-see § 60.17).

(vii) ASTM D4891–89 (Reapproved 2006) (incorporated by reference-see § 60.17).

(viii) GPA 2172–09 (incorporated by reference-see § 60.17).

(ix) Any of the methods specified in section 2.2.7 of Appendix D to part 75.

(x) If the fuel oil supplied to the affected co-fired process heater originates from a single storage tank, the owner or operator may elect to use the storage tank sampling method in section 2.2.4.2 of Appendix D to part 75 instead of daily sampling, except that the most recent value for heating content must be used.

(8) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification based technology to reduce NO_X emissions (*i.e.,* low-NO_X burners or ultra-low NO_X burners) may elect to comply with the monitoring requirements in paragraphs (d)(1) through (7) of this section or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests according to the requirements in § 60.104a(i), establish a maximum excess O_2 operating limit or operating curve according to the requirements in § 60.104a(i)(6) and comply with the O_2 monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance. If an O_2 operating curve is used (*i.e.,* if different O_2 operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of this section, respectively.

(e) *Sulfur monitoring for assessing root cause analysis threshold for affected flares.* Except as described in paragraphs (e)(4) and (h) of this section, the owner or operator of an affected flare subject to § 60.103a(c) through (e) shall determine the total reduced sulfur concentration for each gas line directed to the affected flare in accordance with either paragraph (e)(1), (e)(2) or (e)(3) of this section. Different options may be elected for different gas lines. If a monitoring system is in place that is capable of complying with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section, the owner or operator of a modified flare must comply with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section upon startup of the modified flare. If a monitoring system is not in place that is capable of complying with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section, the owner or operator of a modified flare must comply with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) *Total reduced sulfur monitoring requirements.* The owner or operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration of total reduced sulfur in gas discharged to the flare.

(i) The owner or operator shall install, operate and maintain each total reduced sulfur monitor according to Performance Specification 5 of Appendix B to part 60. The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare (*e.g.,* roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range monitor may be used to comply with the requirements of this paragraph and paragraph (a)(2) of this section provided the applicable span specifications are met.

(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 part 60. For flares that routinely have flow, the owner or operator of each total reduced sulfur monitor shall use EPA Method 15A of Appendix A–5 to part 60 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 part 60. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations. For flares that do not receive routine flow, the alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (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.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part 60 for each total reduced sulfur monitor.

(2) *H_2S monitoring requirements.* The owner or operator shall install, operate, calibrate, and maintain an instrument 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.

(i) The owner or operator shall install, operate and maintain each H_2S monitor according to Performance Specification 7 of Appendix B to part 60. The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare (*e.g.,* roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range H_2S monitor may be used to comply with the requirements of this paragraph and paragraph (a)(2) of this section provided the applicable span specifications are met.

(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 part 60. For flares that routinely have flow, the owner or operator shall use EPA Method 11, 15 or 15A of Appendix A–5 to part 60 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 part 60. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations. For flares that do not receive routine flow, the alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (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.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part 60 for each H_2S monitor.

(iv) In the first 10 operating days after the date the flare must begin to comply with § 60.103a(c)(1), the owner or operator shall collect representative daily samples of the gas discharged to the flare. The samples may be grab samples or integrated samples. The owner or operator shall take subsequent representative daily samples at least once per week or as required in paragraph (e)(2)(ix) of this section.

(v) The owner or operator shall analyze each daily sample for total sulfur using either EPA Method 15A of Appendix A–5 to part 60, EPA Method 16A of Appendix A–6 to part 60, ASTM Method D4468–85 (Reapproved 2006) (incorporated by reference—see § 60.17) or ASTM Method D5504–08 (incorporated by reference—see § 60.17).

(vi) The owner or operator shall develop a 10-day average total sulfur-to-H_2S ratio and 95-percent confidence interval as follows:

(A) Calculate the ratio of the total sulfur concentration to the H_2S concentration for each day during which samples are collected.

(B) Determine the 10-day average total sulfur-to-H_2S ratio as the arithmetic average of the daily ratios calculated in paragraph (e)(2)(vi)(A) of this section.

(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 11 of this section.

$$AR = Ratio_{Avg} \pm 2.262 \times SDev \qquad \text{(Eq. 11)}$$

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.

(vii) For each day during the period when data are being collected to develop a 10-day average, the owner or operator shall estimate the total sulfur concentration using the measured total sulfur concentration measured for that day.

(viii) For all days other than those during which data are being collected to develop a 10-day average, the owner or operator shall multiply the most recent 10-day average total sulfur-to-H_2S ratio by the daily average H_2S concentrations obtained using the monitor as required by paragraph (e)(2)(i) through (iii) of this section to estimate total sulfur concentrations.

(ix) If the total sulfur-to-H_2S ratio for a subsequent weekly sample is outside the acceptable range for the most recent distribution of daily ratios, the owner or operator shall develop a new 10-day average ratio and acceptable range based on data for the outlying weekly sample plus data collected over the following 9 operating days.

(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 12 of this section.

$$TS_{FG} = C_{SO_2} \times F_d \times HHV_{FG} \qquad \text{(Eq. 12)}$$

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.

(4) *Exemptions from sulfur monitoring requirements.* Flares identified in paragraphs (e)(4)(i) through (iv) of this section are exempt from the requirements in paragraphs (e)(1) through (3) of this section. For each such flare, except as provided in paragraph (e)(4)(iv), engineering calculations shall be used to calculate the SO_2 emissions in the event of a discharge that may trigger a root cause analysis under § 60.103a(c)(1).

(i) Flares that can only receive:

(A) Fuel gas streams that are inherently low in sulfur content as described in paragraph (a)(3)(i) through (iv) of this section; and/or

(B) Fuel gas streams that are inherently low in sulfur content for which the owner or operator has applied for an exemption from the H_2S monitoring requirements as described in paragraph (b) of this section.

(ii) Emergency flares, provided that for each such flare, the owner or operator complies with the monitoring alternative in paragraph (g) of this section.

(iii) Flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction, provided that for each such flare, the owner or operator complies with the monitoring alternative in paragraph (g) of this section.

(iv) Secondary flares that receive gas diverted from the primary flare. In the event of a discharge from the secondary flare, the sulfur content measured by the sulfur monitor on the primary flare should be used to calculate SO_2 emissions, regardless of whether or not the monitoring alternative in paragraph (g) of this section is selected for the secondary flare.

(f) *Flow monitoring for flares.* Except as provided in paragraphs (f)(2) and (h) of this section, the owner or operator of an affected flare subject to § 60.103a(c) through (e) shall install, operate, calibrate and maintain, in accordance with the specifications in paragraph (f)(1) of this section, a CPMS to measure and record the flow rate of gas discharged to the flare. If a flow monitor is not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) 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.

(i) Locate the monitor in a position that provides a representative measurement of the total gas flow rate.

(ii) Use a flow sensor with a measurement sensitivity of no more than 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater.

(iii) Use a flow monitor that is maintainable online, is able to continuously correct for temperature and pressure and is able to record flow in standard conditions (as defined in § 60.2) over one-minute averages.

(iv) 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.

(v) 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.

(2) Emergency flares, secondary flares and flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction are not required to install continuous flow monitors; provided, however, that for any such flare, the owner or operator shall comply with the monitoring alternative in paragraph (g) of this section.

(g) *Alternative monitoring for certain flares equipped with water seals.* The owner or operator of an affected flare subject to § 60.103a(c) through (e) that can be classified as either an emergency flare, a secondary flare or a flare equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction may, as an alternative to the sulfur and flow monitoring requirements of paragraphs (e) and (f) of this section, install, operate, calibrate and maintain, in accordance with the requirements in paragraphs (g)(1) through (7) of this section, a CPMS to measure and record the pressure in the flare gas header between the knock-out pot and water seal and to measure and record the water seal liquid level. If the required monitoring systems are not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and locate the liquid seal level monitor in a position that provides a representative measurement of the water column height.

(2) Minimize or eliminate pulsating pressure, vibration and internal and external corrosion.

(3) Use a pressure sensor and level monitor with a minimum tolerance of 1.27 centimeters of water.

(4) Using a manometer, check pressure sensor calibration quarterly.

(5) Conduct calibration checks any time the pressure sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(6) In a cascaded flare system that employs multiple secondary flares, pressure and liquid level monitoring is required only on the first secondary flare in the system (*i.e.,* the secondary flare with the lowest pressure release set point).

(7) This alternative monitoring option may be elected only for flares with four or fewer pressure exceedances required to be reported under § 60.108a(d)(5) (''reportable pressure exceedances'') in any 365 consecutive calendar days. Following the fifth reportable pressure exceedance in a 365-day period, the owner or operator must comply with the sulfur and flow monitoring requirements of paragraphs (e) and (f) of this section as soon as practical, but no later than 180 days after the fifth reportable pressure exceedance in a 365-day period.

(h) *Alternative monitoring for flares located in the BAAQMD or SCAQMD.* An affected flare subject to this subpart located in the BAAQMD may elect to comply with the monitoring requirements in both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (e) and (f) of this section. An affected flare subject to this subpart located in the SCAQMD may elect to comply with the monitoring requirements in SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (e) and (f) of this section.

(i) *Excess emissions.* For the purpose of reports required by § 60.7(c), periods of excess emissions for fuel gas combustion devices subject to the emissions limitations in § 60.102a(g) and flares subject to the concentration requirement in § 60.103a(h) are defined as specified in paragraphs (i)(1) through (5) of this section. Determine a rolling 3-hour or a rolling daily average as the arithmetic average of the applicable 1-hour averages (*e.g.,* a rolling 3-hour average is the arithmetic average of three contiguous 1-hour averages). Determine a rolling 30-day or a rolling 365-day average as the arithmetic average of the applicable daily averages (*e.g.,* a rolling 30-day average is the arithmetic average of 30 contiguous daily averages).

(1) *SO_2 or H_2S limits for fuel gas combustion devices.* (i) If the owner or operator of a fuel gas combustion device elects to comply with the SO_2 emission limits in § 60.102a(g)(1)(i), each rolling 3-hour period during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system required under paragraph (a)(1) of this section exceeds 20 ppmv, and each rolling 365-day period during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system required under paragraph (a)(1) of this section exceeds 8 ppmv.

(ii) If the owner or operator of a fuel gas combustion device elects to comply with the H_2S concentration limits in § 60.102a(g)(1)(ii), each rolling 3-hour period during which the average concentration of H_2S as measured by the

H_2S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H_2S continuous monitoring system under paragraph (a)(2) of this section exceeds 60 ppmv.

(iii) If the owner or operator of a fuel gas combustion device becomes subject to the requirements of daily stain tube sampling in paragraph (b)(3)(iii) of this section, each day during which the daily concentration of H_2S exceeds 162 ppmv and each rolling 365-day period during which the average concentration of H_2S exceeds 60 ppmv.

(2) H_2S concentration limits for flares. (i) Each rolling 3-hour period during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv.

(ii) If the owner or operator of a flare becomes subject to the requirements of daily stain tube sampling in paragraph (b)(3)(iii) of this section, each day during which the daily concentration of H_2S exceeds 162 ppmv.

(3) *Rolling 30-day average NO_X limits for fuel gas combustion devices.* Each rolling 30-day period during which the average concentration of NO_X as measured by the NO_X continuous monitoring system required under paragraph (c) or (d) of this section exceeds:

(i) For a natural draft process heater, 40 ppmv and, if monitored according to § 60.107a(d), 0.040 lb/MMBtu;

(ii) For a forced draft process heater, 60 ppmv and, if monitored according to § 60.107a(d), 0.060 lb/MMBtu; and

(iii) For a co-fired process heater electing to comply with the NO_X limit in § 60.102a(g)(2)(iii)(A) or (g)(2)(iv)(A), 150 ppmv.

(iv) The site-specific limit determined by the Administrator under § 60.102a(i).

(4) *Daily NO_X limits for fuel gas combustion devices.* Each day during which the concentration of NO_X as measured by the NO_X continuous monitoring system required under paragraph (d) of this section exceeds the daily average emissions limit calculated using Equation 3 in § 60.102a(g)(2)(iii)(B) or Equation 4 in § 60.102a(g)(2)(iv)(B).

(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) of this section exceeds the O_2 operating limit or operating curve determined during the most recent biennial performance test.

■ 18. Section 60.108a is amended by:
■ a. Revising paragraph (b);
■ b. Revising paragraph (c)(1);
■ c. Revising paragraph (c)(6) introductory text and paragraphs (c)(6)(ii) through (vi);
■ d. Adding paragraphs (c)(6)(vii), (viii), (ix), (x) and (xi);
■ e. Adding paragraph (c)(7); and
■ f. Revising paragraph (d)(5).

The revisions and additions read as follows:

§ 60.108a Recordkeeping and reporting requirements.

* * * * *

(b) Each owner or operator subject to an emissions limitation in § 60.102a shall notify the Administrator of the specific monitoring provisions of §§ 60.105a, 60.106a and 60.107a with which the owner or operator intends to comply. Each owner or operator of a co-fired process heater subject to an emissions limitation in § 60.102a(g)(2)(iii) or (iv) shall submit to the Administrator documentation showing that the process heater meets the definition of a co-fired process heater in § 60.101a. Notifications required by this paragraph shall be submitted with the notification of initial startup required by § 60.7(a)(3).

(c) * * *

(1) A copy of the flare management plan.

* * * * *

(6) Records of discharges greater than 500 lb SO_2 in any 24-hour period from any affected flare, discharges greater than 500 lb SO_2 in excess of the allowable limits from a fuel gas combustion device or sulfur recovery plant and discharges to an affected flare in excess of 500,000 scf above baseline in any 24-hour period as required by § 60.103a(c). If the monitoring alternative provided in § 60.107a(g) is selected, the owner or operator shall record any instance when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in § 60.103a(a)(3)(vii)(C). The following information shall be recorded no later than 45 days following the end of a discharge exceeding the thresholds:

* * * * *

(ii) The date and time the discharge was first identified and the duration of the discharge.

(iii) The measured or calculated cumulative quantity of gas discharged over the discharge duration. If the discharge duration exceeds 24 hours, record the discharge quantity for each 24-hour period. For a flare, record the measured or calculated cumulative quantity of gas discharged to the flare over the discharge duration. If the discharge duration exceeds 24 hours, record the quantity of gas discharged to the flare for each 24-hour period. Engineering calculations are allowed for fuel gas combustion devices, but are not allowed for flares, except for those complying with the alternative monitoring requirements in § 60.107a(g).

(iv) For each discharge greater than 500 lb SO_2 in any 24-hour period from a flare, the measured total sulfur concentration or both the measured H_2S concentration and the estimated total sulfur concentration in the fuel gas at a representative location in the flare inlet.

(v) For each discharge greater than 500 lb SO_2 in excess of the applicable short-term emissions limit in § 60.102a(g)(1) from a fuel gas combustion device, either the measured concentration of H_2S in the fuel gas or the measured concentration of SO_2 in the stream discharged to the atmosphere. Process knowledge can be used to make these estimates for fuel gas combustion devices, but cannot be used to make these estimates for flares, except as provided in § 60.107a(e)(4).

(vi) For each discharge greater than 500 lb SO_2 in excess of the allowable limits from a sulfur recovery plant, either the measured concentration of reduced sulfur or SO_2 discharged to the atmosphere.

(vii) For each discharge greater than 500 lb SO_2 in any 24-hour period from any affected flare or discharge greater than 500 lb SO_2 in excess of the allowable limits from a fuel gas combustion device or sulfur recovery plant, the cumulative quantity of H_2S and SO_2 released into the atmosphere. For releases controlled by flares, assume 99-percent conversion of reduced sulfur or total sulfur to SO_2. For fuel gas combustion devices, assume 99-percent conversion of H_2S to SO_2.

(viii) The steps that the owner or operator took to limit the emissions during the discharge.

(ix) The root cause analysis and corrective action analysis conducted as required in § 60.103a(d), including an identification of the affected facility, the date and duration of the discharge, a statement noting whether the discharge 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 § 60.103a(e).

(x) For any corrective action analysis for which corrective actions are required in § 60.103a(e), 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.

(xi) For each discharge from any affected flare that is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare, a statement that a root cause analysis and corrective action analysis are not necessary because the owner or operator followed the flare management plan.

(7) If the owner or operator elects to comply with § 60.107a(e)(2) for a flare, records of the H_2S and total sulfur analyses of each grab or integrated sample, the calculated daily total sulfur-to-H_2S ratios, the calculated 10-day average total sulfur-to-H_2S ratios and the 95-percent confidence intervals for each 10-day average total sulfur-to-H_2S ratio.

(d) * * *

(5) The information described in paragraph (c)(6) of this section for all discharges listed in paragraph (c)(6) of this section. For a flare complying with the monitoring alternative under § 60.107a(g), following the fifth discharge required to be recorded under paragraph (c)(6) of this section and reported under this paragraph, the owner or operator shall include notification that monitoring systems will be installed according to § 60.107a(e) and (f) within 180 days following the fifth discharge.

* * * * *

■ 19. Section 60.109a is amended by revising paragraph (b) introductory text and adding paragraph (b)(4) to read as follows:

§ 60.109a Delegation of authority.

* * * * *

(b) In delegating implementation and enforcement authority of this subpart to a state, local or tribal agency, the approval authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the state, local or tribal agency.

* * * * *

(4) Approval of an application for an alternative means of emission limitation under § 60.103a(j) of this subpart.

■ 20. Table 1 to subpart Ja is added to read as follows:

TABLE 1 TO SUBPART JA OF PART 60—MOLAR EXHAUST VOLUMES AND MOLAR HEAT CONTENT OF FUEL GAS CONSTITUENTS

Constituent	MEV[a] dscf/mol	MHC[b] Btu/mol
Methane (CH_4)	7.29	842
Ethane (C_2H_6)	12.96	1,475
Hydrogen (H_2)	1.61	269
Ethene (C_2H_4)	11.34	1,335
Propane (C_3H_8)	18.62	2,100
Propene (C_3H_6)	17.02	1,947
Butane (C_4H_{10})	24.30	2,717
Butene (C_4H_8)	22.69	2,558
Inerts	0.85	0

[a] MEV = molar exhaust volume, dry standard cubic feet per gram-mole (dscf/g-mol) at standard conditions of 68 °F and 1 atmosphere.

[b] MHC = molar heat content (higher heating value basis), Btu per gram-mole (Btu/g-mol).

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