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40 CFR Part 60

Standards of Performance for Petroleum Refineries; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2007–0011; FRL–8563–2]

RIN 2060–AN72

Standards of Performance for Petroleum Refineries

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is issuing final amendments to the current Standards of Performance for Petroleum Refineries. This action also promulgates separate standards of performance for new, modified, or reconstructed process units at petroleum refineries. The final standards for new process units include emissions limitations and work practice standards for fluid catalytic cracking units, fluid coking units, delayed coking units, fuel gas combustion devices, and sulfur recovery plants. These final standards reflect demonstrated improvements in emissions control technologies and work practices that have occurred since promulgation of the current standards.

DATES: These final rules are effective on June 24, 2008. The incorporation by reference of certain publications listed in the final rules is approved by the Director of the Federal Register as of June 24, 2008.

ADDRESSES: 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 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: Mr. Robert B. Lucas, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, Coatings and Chemicals Group (E143–01), Environmental Protection Agency, Research Triangle Park, NC 27711, *telephone number:* (919) 541–0884; *fax number:* (919) 541–0246; *e-mail address: lucas.bob@epa.gov.*

SUPPLEMENTARY INFORMATION:

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 proposed 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 Worldwide 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.

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 August 25, 2008. 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 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.

D. How is this document organized?

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II. Background Information

New source performance standards (NSPS) implement CAA section 111(b) and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. The primary purpose of the NSPS is to attain and maintain ambient air quality by ensuring that the best demonstrated emission control technologies are installed as the industrial infrastructure is modernized. Since 1970, the NSPS have been successful in achieving long-term emissions reductions in numerous industries by assuring cost-effective controls are installed on new, reconstructed, or modified sources.

Section 111 of the CAA requires that NSPS reflect the application of the best system of emission reductions which (taking into consideration the cost of achieving such emission reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is commonly referred to as best demonstrated technology (BDT).

Section 111(b)(1)(B) of the CAA requires EPA to periodically review and revise the standards of performance, as necessary, 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 (72 FR 27278, May 14, 2007). In response to several requests, we extended the 60-day comment period from July 13, 2007, to August 27, 2007 (72 FR 35375, June 28, 2007). We also issued a notice of data availability (NODA) (72 FR 69175, December 7, 2007) to notify the public that additional information had been added to the docket; the NODA also extended the public comment period on the proposed rule to January 7, 2008. We received a total of 38 comments from refineries, industry trade associations, and consultants; State and local environmental and public health agencies; environmental groups; and members of the public during the extended comment period, and 8 additional comments on the NODA. These final rules reflect our full consideration of all of the comments we received. Detailed responses to the comments not included in this preamble are contained in the Response to Comments document which is included in the docket for this rulemaking.

III. Summary of the Final Rules and Changes Since Proposal

We are promulgating several amendments to provisions in the existing NSPS in 40 CFR part 60, subpart J. Many of these amendments are technical clarifications and corrections that are also included in the final standards in 40 CFR part 60, subpart Ja. For example, we are revising the definition of ''fuel gas'' to indicate that vapors collected and combusted to comply with certain wastewater and marine vessel loading provisions are not considered fuel gas. Consequently, these vapors are exempt from the sulfur dioxide (SO_2) treatment standard in 40 CFR 60.104(a)(1) and are not required to be monitored. We are also finalizing certain monitoring exemptions that we proposed for fuel gases that are identified as inherently low sulfur or demonstrated to contain a low sulfur content. See 40 CFR 60.105(a)(4)(iv). We are also revising the coke burn-off equation to account for oxygen (O_2)—enriched air streams. Other amendments include clarification of definitions and correction of grammatical and typographical errors.

The final standards in 40 CFR part 60, subpart Ja include emission limits for fluid catalytic cracking units (FCCU), fluid coking units (FCU), sulfur recovery plants (SRP), and fuel gas combustion devices. Subpart Ja also includes work practice standards for reducing emissions of volatile organic compounds (VOC) from flares, minimizing SO_2 emissions from fuel gas combustion devices and SRP, and for reducing emissions of VOC from delayed coking units. Only those affected facilities that commence construction, modification, or reconstruction after May 14, 2007 will be affected by the standards in subpart Ja. Units for which construction, modification, or reconstruction commenced on or before May 14, 2007 must continue to comply with the applicable standards under the current NSPS in 40 CFR part 60, subpart J, as amended.

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

As proposed, we are amending the definition of ''fuel gas'' to specifically exclude vapors that are collected and combusted in an air pollution control device installed to comply with a specified wastewater or marine vessel loading emissions standard. The thermal combustion control devices themselves are still considered to be affected fuel gas combustion devices if they combust other gases that meet the definition of fuel gas, and all auxiliary fuel gas fired to these devices are subject to the fuel gas limit; however, continuous monitoring is not required for the vapors collected from wastewater or marine vessel loading operations that are being incinerated because these gases are not considered to be fuel gases under the definition of ''fuel gas'' in 40 CFR part 60, subpart J.

We are also finalizing exemptions for certain fuel gas streams from all continuous monitoring requirements. See 40 CFR 60.105(a)(4)(iv). Monitoring is not required for combustion in a flare of process upset gases or flaring of gases from relief valve leakage or emergency malfunctions since these streams are exempt from the standard under 40 CFR 60.104(a)(1). Additionally, monitoring is not required for inherently low sulfur fuel gas streams since the emissions generated by combusting such streams will necessarily be well below the standard. These streams include pilot gas flames, gas streams that meet commercial-grade product specifications with a sulfur content of 30 parts per million by volume (ppmv) or less, fuel gases produced by process

units that are intolerant to sulfur contamination, and fuel gas streams that an owner or operator can demonstrate are inherently low-sulfur. Owners and operators are required to document the exemption for which each fuel gas stream applies and ensure that the stream remains qualified for that exemption.

For accuracy in the calculation of the coke burn-off rate, we are revising the coke burn-off rate equation in 40 CFR 60.106(b)(3) to be consistent with the equation in 40 CFR 63.1564(b)(4)(i) of the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (40 CFR part 63, subpart UUU). This revision adds a fourth term to the coke burn-off rate equation to account for the use of O_2-enriched air. Other revisions to the equation change the constant values and the units of the resulting coke burn-off rate from Megagrams per hour (Mg/hr) and tons per hour (tons/hr) to kilograms per hour (kg/hr) and pounds per hour (lb/hr).

We proposed to amend the definition of ''Claus sulfur recovery plant'' in 40 CFR 60.101(i) to clarify that the SRP may consist of multiple units and that primary sulfur pits are considered part of the Claus SRP consistent with the Agency's current position. Commenters expressed concern that change to a 40 CFR part 60, subpart J definition that could lead to retroactive non-compliance. We disagree with those concerns as we believe the definition as currently written provides for such coverage. Nonetheless, we are not amending this definition in the final amendments for subpart J and will continue to address individual applicability issues under our applicability determination procedures. Similarly, we proposed revisions to the subpart J definitions of ''oxidation control system'' and ''reduction control system'' in 40 CFR 60.101(j) and 40 CFR 60.101(k), respectively, to clarify that these systems were intended to recycle the sulfur back to the Claus SRP. The proposed amendments needlessly limit the types of tail gas treatment systems that can be used; therefore, we are not amending these definitions in the final amendments for subpart J.

The final amendments also include technical corrections to fix references and other miscellaneous errors in 40 CFR part 60, subpart J. Table 1 of this preamble describes the miscellaneous technical corrections not previously described in this preamble that are included in the amendments to subpart J.

TABLE 1.—TECHNICAL CORRECTIONS TO 40 CFR PART 60, SUBPART J

Section	Technical correction and reason
60.100	Replace instances of ''construction or modification'' with ''construction, reconstruction, or modification.''
60.100(a)	Replace ''except Claus plants of 20 long tons per day (LTD) or less'' with ''except Claus plants with a design capacity for sulfur feed of 20 long tons per day (LTD) or less'' to clarify that the size cutoff is based upon design capacity and sulfur content in the inlet stream rather than the amount of sulfur produced.
60.100(b)	Insert ending date for applicability of 40 CFR part 60, subpart J (one date for flares and another date for all other affected facilities); sources beginning construction, reconstruction, or modification after this date will be subject to 40 CFR part 60, subpart Ja.
60.102(b)	Replace ''g/MJ'' with ''grams per Gigajoule (g/GJ)'' to correct units.
60.104(b)(1)	Replace ''sulfur dioxide'' with ''SO_2'' and replace ''50 ppm by volume (vppm)'' with ''50 ppm by volume (ppmv)'' for consistency in unit and acronym definition.
60.104(b)(2)	Add ''to reduce SO_2 emissions'' to the end of the phrase ''Without the use of an add-on control device'' at the beginning of the paragraph to clarify the type of control device to which this paragraph refers; replace ''sulfur dioxide'' with ''SO_2'' for consistency in acronym definition.
60.105(a)(3)	Add ''either'' before ''an instrument for continuously monitoring'' and replace ''except where an H_2S monitor is installed under paragraph (a)(4)'' with ''or monitoring as provided in paragraph (a)(4)'' to more accurately refer to the requirements of § 60.105(a)(4) and clarify that there is a choice of monitoring requirements.
60.105(a)(3)(iv)	Replace ''accurately represents the S_2 emissions'' with ''accurately represents the SO_2 emissions'' to correct a typographical error.
60.105(a)(4)	Replace ''In place'' with ''Instead'' at the beginning of this paragraph and add ''for fuel gas combustion devices subject to § 60.104(a)(1)'' after ''paragraph (a)(3) of this section'' to clarify that there is a choice of monitoring requirements.
60.105(a)(8)	Replace ''seeks to comply with § 60.104(b)(1)'' with ''seeks to comply specifically with the 90-percent reduction option under § 60.104(b)(1)'' to clearly identify the emission limit option to which the monitoring requirement in this paragraph refers.
60.105(a)(8)(i)	Change ''shall be set 125 percent'' to ''shall be set at 125 percent'' to correct a grammatical error; replace ''sulfur dioxide'' with ''SO_2'' for consistency in acronym definition.
60.106(e)(2)	Replace the incorrect reference to 40 CFR 60.105(a)(1) with a correct reference to 40 CFR 60.104(a)(1); add ''The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 of Appendix A–4 to part 60.'' after the first sentence of this paragraph to include a voluntary consensus method.
60.107(c)(1)(i)	Replace both occurrences of ''50 vppm'' with ''50 ppmv'' for consistency in unit definition.
60.107(f)	Redesignate current 40 CFR 60.107(e) as 40 CFR 60.107(f) to allow space for a new paragraph (e).
60.107(g)	Redesignate current 40 CFR 60.107(f) as 40 CFR 60.107(g) to allow space for a new paragraph (e).
60.108(e)	Replace the incorrect reference to 40 CFR 60.107(e) with a correct reference to 40 CFR 60.107(f).

B. What are the final requirements for new fluid catalytic cracking units and new fluid coking units (40 CFR part 60, subpart Ja)?

The final standards for new FCCU include emission limits for particulate matter (PM), SO_2, nitrogen oxides (NO_X), and carbon monoxide (CO). The final standards include no universal opacity limit because the opacity limit in 40 CFR part 60, subpart J is intended to ensure compliance with the PM limit. 40 CFR part 60, subpart Ja requires that sources use direct PM monitoring, bag leak detection systems, or parameter monitoring (along with annual emission tests) to ensure compliance with the PM limit. A provision for a site-specific opacity operating limit is provided for units that meet the PM emission limits using a cyclone.

For PM emissions from new FCCU and new FCU, we proposed a PM limit of 0.5 pounds (lb)/1,000 lb coke burnoff in the regenerator or (if a PM continuous emission monitoring system (CEMS) is

used), 0.020 grains per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air. We have revised the final PM standards to establish separate limits for modified or reconstructed FCCU (1 lb/1,000 lb coke burn or 0.040 gr/dscf corrected to 0 percent excess air) and newly constructed FCCU (0.5 lb/1,000 lb coke burn or 0.020 gr/dscf corrected to 0 percent excess air). The final PM limit for new, modified, or reconstructed FCU is 1 lb/1,000 lb coke burn or 0.040 gr/dscf corrected to 0 percent excess air.

Initial compliance with the PM emission limits for FCCU and FCU is determined using EPA Method 5, 5B or 5F (40 CFR part 60, appendix A–3) instead of being restricted to only EPA Method 5 as previously proposed. Procedures for computing the PM emission rate using the total PM concentration, effluent gas flow rate, and coke burn-off rate are the same as in 40 CFR part 60, subpart J, as amended. To demonstrate ongoing compliance, an owner or operator must monitor PM emission control device operating parameters and conduct annual PM performance tests, use a PM CEMS, or operate bag leak detection systems and conduct annual PM performance tests. A new alternative allows refineries with wet scrubbers as PM control devices to use the approved alternative in 40 CFR 63.1573(a) for determining exhaust gas flow rate instead of a continuous parameter monitoring system (CPMS). An alternative to the requirements for monitoring the pressure drop from wet scrubbers that are equipped with jet ejectors or atomizing spray nozzles is to conduct a daily check of the air or water pressure to the nozzles and record the results of each inspection. The final rule also includes procedures for establishing an alternative opacity operating limit for refiners that use continuous opacity monitoring systems (COMS); this alternative is allowed only for units that choose to comply with the PM limit using cyclones. If operating parameters are used to demonstrate ongoing compliance, the owner or operator must monitor the same parameters during the initial performance test, and develop operating parameter limits for the applicable parameters. The operating limits must be based on the three-run average of the values for the applicable parameters measured over the three test runs. If ongoing compliance is demonstrated using a PM CEMS, the CEMS must meet the conditions in Performance Specification 11 (40 CFR part 60, appendix B) and the quality assurance (QA) procedures in Procedure 2, 40 CFR part 60, appendix F. The relative response audits must be conducted annually (in lieu of annual performance tests for units not employing a PM CEMS) and response correlation audits must be conducted once every 5 years.

For NO_X emissions from the affected FCCU and FCU, we proposed a limit of 80 ppmv based on a 7-day rolling average (dry basis corrected to 0 percent excess air) and co-proposed having no limit for FCU. We are adopting the 80 ppmv NO_X emission limits for FCCU and FCU as proposed. Initial compliance with the 80 ppmv emission limit is demonstrated by conducting a performance evaluation of the CEMS in accordance with Performance Specification 2 in 40 CFR part 60, appendix B, with Method 7 (40 CFR part 60, appendix A–4) as the reference method. Ongoing compliance with these emission limits is determined using the CEMS to measure NO_X emissions as discharged to the atmosphere, averaged over 7-day periods.

No changes have been made to the proposed SO_2 emission limits for affected FCCU and FCU. The final SO_2 emission limits are to maintain SO_2 emissions to the atmosphere less than or equal to 50 ppmv on a 7-day rolling average basis, and less than or equal to 25 ppmv on a 365-day rolling average basis (both limits corrected to 0 percent moisture and 0 percent excess air). Initial compliance with the final SO_2 emission limits are demonstrated by conducting a performance evaluation of the SO_2 CEMS in accordance with Performance Specification 2 (40 CFR part 60, Appendix B) with Method 6, 6A, or 6C (40 CFR part 60, Appendix A–4) as the reference method. Ongoing compliance with both SO_2 emission limits is determined using the CEMS to measure SO_2 emissions as discharged to the atmosphere, averaged over the 7-day and 365-day averaging periods.

No changes have been made since proposal to the CO limits. The final CO emission limit for the affected FCCU and FCU is 500 ppmv (1-hour average, dry at 0 percent excess air). Initial compliance with this emission limit is demonstrated by conducting a performance evaluation for the CEMS in accordance with Performance Specification 4 (40 CFR part 60, appendix B) with Method 10 or 10A (40 CFR part 60, Appendix A–4) as the reference method. For Method 10 (40 CFR part 60, Appendix A–4), the integrated sampling technique is to be used. Ongoing compliance with this emission limit is determined on an hourly basis using the CEMS to measure CO emissions as discharged to the atmosphere. An exemption from monitoring may be requested for an FCCU or FCU if the owner or operator can demonstrate that ''average CO emissions'' are less than 50 ppmv (dry basis). As proposed, units that are exempted from the CO monitoring requirements must comply with control device operating parameter limits.

C. What are the final requirements for new sulfur recovery plants (40 CFR part 60, subpart Ja)?

For new, modified, and reconstructed SRP with a capacity greater than 20 long tons per day (LTD) (large SRP), we proposed a limit of 250 ppmv total sulfur (combined SO_2 and reduced sulfur compounds) as SO_2 (dry basis at 0 percent excess air determined on a 12-hour rolling average basis). The refinery could comply with the limit for each process train or release point or with a flow rate weighted average of 250 ppmv for all release points. For affected SRP with a capacity less than 20 LTD (small SRP), we proposed a mass emissions limit for total sulfur equal to 1 weight percent or less of sulfur recovered (determined hourly on a 12-hour rolling average basis).

In this final rule, we are adopting the current limits in subpart J (which include separate emission limits for oxidative and reductive systems) for affected large SRP. For these affected SRP, the final limits for SRP having an oxidation control system or a reduction control system followed by incineration is 250 ppmv (dry basis) of SO_2 at zero percent excess air. For an affected SRP with a reduction control system not followed by incineration, the final limit is 300 ppmv of reduced sulfur compounds and 10 ppmv of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air. If the SRP consists of multiple process trains or release points, the refinery can comply with the limit for each process train or release point or with a flow rate weighted average of 250 ppmv for all release points. A new alternative allows refineries to use a correlation to calculate their effective emission limit for Claus SRP that use oxygen enrichment in the Claus burner. For a small affected SRP, the sulfur recovery efficiency standard is based on a sulfur recovery efficiency of 99 percent. However, due to the difficulties associated with on-going monitoring of SRP recovery efficiency, in this final rule, we are promulgating concentration limits that correlate with a sulfur recovery efficiency of 99 percent. For a Claus unit with an oxidative control system or any small SRP followed by an incinerator the emission limit is 2,500

ppmv (dry basis) of SO_2 at zero percent excess air. For all other small SRP, the emission limit is 3,000 ppmv reduced sulfur compound and 100 ppmv H_2S, each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air. A similar correlation is provided for small Claus SRP that use oxygen enrichment, similar to that provided for large SRP. The standards for small SRP apply to all release points from the SRP combined (note that secondary sulfur storage units are not considered part of the SRP). We are not promulgating the H_2S limit of 10 ppmv (dry basis, at 0 percent excess air determined on a 12-hour rolling average basis) or related operating limits that were included in § 60.102a(e) and (f) of the proposed rule.

Initial compliance with the emission limit for large SRP is demonstrated by conducting a performance evaluation for the SO_2 CEMS in accordance with either Performance Specification 2 (40 CFR part 60, Appendix B) for SRP with oxidation control systems or reduction control systems followed by incineration, or Performance Specification 5 (40 CFR part 60, Appendix B) for SRP with reduction control systems not followed by incineration. The owner or operator must operate and maintain oxygen monitors according to Performance Specification 3 (40 CFR part 60, Appendix B).

Ongoing compliance with the SO_2 limits for large SRP is determined using an SO_2 CEMS (for oxidative or reductive systems followed by incineration) or a CEMS that uses an air or O_2 dilution and oxidation system to convert the reduced sulfur to SO_2 and then measures the total resultant SO_2 concentration (for reductive systems not followed by incineration). An O_2 monitor is also required for converting the measured combined SO_2 concentration to the concentration at 0 percent O_2.

Initial and ongoing compliance requirements for small SRP are the same as for large SRP.

D. What are the final requirements for new fuel gas combustion devices (40 CFR part 60, subpart Ja)?

In the subpart Ja proposal, we divided fuel gas combustion devices into two separate affected sources: ''process heaters'' and ''other fuel gas combustion devices.'' In response to comments, we have eliminated the proposed definition of ''other fuel gas combustion devices'' and revised the standards to either refer to fuel gas combustion devices, which include process heaters, or to refer specifically to process heaters. This revision makes the definition of ''fuel gas combustion devices'' consistent with subpart J. Based on public comments, we have also added a definition of ''flare'' as a subcategory of fuel gas combustion devices. The owner or operator of an affected flare must comply with the fuel gas combustion device requirements as well as specific provisions for flares as described in section III.E of this preamble.

We proposed a primary sulfur dioxide emission limit for fuel gas combustion devices of 20 ppmv or less SO_2 (dry at 0 percent excess air) on a 3-hour rolling average basis and 8 ppmv or less on a 365-day rolling average basis. We also proposed an alternative limit of 160 ppmv H_2S or, in the case of coker-derived fuel gas, 160 ppmv total reduced sulfur (TRS), on a 3-hour rolling average basis and 60 ppmv or less on a 365-day rolling average basis. We are promulgating the 20 ppmv and 8 ppmv limits for SO_2 as proposed. We are also promulgating the alternative limit except that the limits are expressed and measured as H_2S in all cases. The alternative H_2S limit is 162 ppmv or less in the fuel gas on a 3-hour rolling average basis and 60 ppmv or less in the fuel gas on a 365-day rolling average basis. The alternative limit of 162 ppmv is based on standard conditions, which are defined in the NSPS General Provisions at 40 CFR 60.2 as being 68°F and 1 atmosphere. Using these as standard conditions, the subpart J emission limit is equivalent to 162 ppmv H_2S rather than 160 ppmv. The final rule does not include an alternative TRS limit for SO_2.

Initial compliance with the 20 ppmv SO_2 limit or the 162 ppmv H_2S concentration limits is demonstrated by conducting a performance evaluation for the CEMS. The performance evaluation for an SO_2 CEMS is conducted in accordance with Performance Specification 2 in 40 CFR part 60, Appendix B. The performance evaluation for an H_2S CEMS is conducted in accordance with Performance Specification 7 in 40 CFR part 60, Appendix B. Ongoing compliance with the sulfur oxides emission limits is determined using the applicable CEMS to measure either SO_2 in the exhaust gas to the atmosphere or H_2S in the fuel gas, averaged over the 3-hour and 365-day averaging periods.

Similar to clarifications for 40 CFR part 60, subpart J, the definition of ''fuel gas'' includes exemptions for vapors collected and combusted in an air pollution control device installed to comply with specified wastewater or marine vessel loading provisions. We are also streamlining the process for an owner or operator to demonstrate that a fuel gas stream not explicitly exempted from continuous monitoring is inherently low sulfur.

For new, modified, or reconstructed process heaters with a rated capacity greater than 20 million British thermal units per hour (MMBtu/hr), we proposed a NO_X limit of 80 ppmv (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis. The final NO_X emission limit for affected process heaters is 40 ppmv on a 24-hour rolling average basis (dry at 0 percent excess air) for process heaters greater than 40 MMBtu/hr. For process heaters greater than 100 MMBtu/hr capacity, initial compliance with the 40 ppmv emission limit is demonstrated by conducting a performance evaluation of the CEMS in accordance with Performance Specification 2 in 40 CFR part 60, Appendix B. For process heaters between 40 MMBtu/hr and 100 MMBtu/hr capacity, initial compliance is demonstrated using EPA Method 7 (40 CFR part 60, Appendix A–4). For process heaters greater than 100 MMBtu/hr capacity, ongoing compliance with this emission limit is determined using the CEMS to measure NO_X emissions as discharged to the atmosphere, averaged over 24-hour periods. For process heaters between 40 MMBtu/hr and 100 MMBtu/hr capacity, ongoing compliance with this emission limit is determined using biennial performance tests.

E. What are the final work practice standards (40 CFR part 60, subpart Ja)?

We proposed three work practice standards to reduce SO_2, VOC, and NO_X emissions from flares and from startup, shutdown, and malfunction events and to reduce VOC and SO_2 emissions from delayed coking units. We also co-proposed to require only one of these work practice standards: the requirement to depressure delayed coking units. This proposed standard required new delayed coking units to depressure to 5 pounds per square inch gauge (psig) during reactor vessel depressuring and vent the exhaust gases to the fuel gas system.

We are promulgating a work practice standard for delayed coking units and modified requirements to reduce emissions from flares. The final work practice standard for delayed cokers requires affected delayed coking units to depressure to 5 pounds per square inch gauge (psig) during reactor vessel depressuring. We are requiring the exhaust gases to be vented to the fuel gas system as proposed or to a flare.

To reduce SO_2 emissions from the combustion of sour fuel gases, the final rule requires refineries to conduct a root

cause analysis of any emissions limit exceedance or process start-up, shutdown, upset, or malfunction that causes a discharge into the atmosphere, either directly or indirectly, from any fuel gas combustion device or sulfur recovery plant subject to the provisions of subpart Ja that exceeds 500 pounds per day (lb/day) of SO_2. Recordkeeping and reporting requirements apply in the event of such a discharge. Newly constructed and reconstructed flares must comply with these requirements immediately upon startup. Modified flares must comply no later than the first discharge that occurs after that flare has been an affected flare for 1 year.

In response to comments regarding the work practice standards for fuel gas producing units and associated difficulties with no routine flaring, we re-evaluated the work practice standards and have decided not to promulgate a work practice standard for fuel gas producing units. Rather, we have decided to define a flare as an affected facility and adopt regulations applicable to it. Therefore, we are not promulgating the proposed definition of ''fuel gas producing unit'' and the proposed requirement for ''no routine flaring.'' Instead, we are promulgating the following requirements for flares that become affected facilities after June 24, 2008: (1) Flare fuel gas flow rate monitoring; (2) a flare fuel gas flow rate limit; and (3) a flare management plan. Affected flares cannot exceed a flow rate of 250,000 standard cubic feet per day (scfd) on a 30-day rolling average basis. In cases where the flow would exceed this value, the owner or operator would install a flare gas recovery system or implement other methods to reduce flaring from the affected flare. To demonstrate compliance with the flow rate limitations, flow rate monitors must be installed and operated. Newly constructed and reconstructed flares must comply with the flow rate limitations and the monitoring requirements immediately upon startup. Modified flares must comply with the flow rate limitations and the associated monitoring provisions no later than 1 year after the flare becomes an affected facility. A provision is provided for an exclusion from the flow limitation for times when the refinery can demonstrate that the refinery produces more fuel gas than it needs to fuel the refinery combustion devices (*i.e.*, it is fuel gas rich) or that the flow is due to an upset or malfunction, provided the refinery follows procedures outlined in the flare management plan. The flare management plan should address potential causes of fuel gas imbalances (*i.e.*, excess fuel gas) and records to be maintained to document these periods. As described in 40 CFR 60.103a(a), the flare management plan must include a diagram illustrating all connections to each affected flare, identification of the flow rate monitoring device and a detailed description of the manufacturer's specifications regarding quality assurance procedures, procedures to minimize flaring during planned start-up and shut down events, and procedures for implementing root cause analysis when daily flow to the flare exceeds 500,000 scfd. The root cause analysis procedures should address the evaluation of potential causes of upsets or malfunctions and records to be maintained to document the cause of the upset or malfunction. Newly constructed and reconstructed flares must comply with the flare management plan requirements immediately upon startup. Modified flares must comply with the flare management plan requirements no later than 1 year after the flare becomes an affected facility. Additionally, as described above, the owner or operator of a modified flare must conduct the first root cause analysis no later than the first discharge that occurs after that flare has been an affected flare for 1 year. Excess emission events for the flow rate limit of 250,000 scfd and the result of root cause analysis must be reported in the semi-annual compliance reports.

Because affected flares are also affected fuel gas combustion devices, the root cause analysis for SO_2 emissions exceeding 500 lbs/day also applies to all affected flares. However, compliance with the 500 lb/day root cause analysis will also require continuous monitoring of total reduced sulfur of all gases flared. Although all fuel gas combustion devices are required to comply with continuous H_2S monitoring of fuel gas, flares routinely accept gases from upsets, malfunctions and startup and shutdown events, and H_2S or sulfur monitoring is not specifically required for these gases. In subpart Ja, we explicitly require TRS monitoring for flares that become affected facilities after June 24, 2008 to ensure that the 500 lb/day SO_2 trigger is accurately measured. The owner or operator of a modified flare must install and operate the TRS monitoring instrument no later than 1 year after the flare becomes an affected facility. The owner or operator of a newly constructed or reconstructed flare must install and operate the TRS monitoring instrument no later than start-up of the flare.

F. What are the modification and reconstruction provisions?

Existing affected facilities that commence modification or reconstruction after May 14, 2007, are subject to the final standards in 40 CFR part 60, subpart Ja. A modification is any physical or operational change to an existing affected facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies (see 40 CFR 60.14). Changes to an existing affected facility that do not result in an increase in the emission rate, as well as certain changes that have been exempted under the General Provisions (see 40 CFR 60.14(e)), are not considered modifications.

The intermittent operation of a flare makes it difficult to use the criteria of 40 CFR 60.14 to determine when a flare is modified; therefore, we have specified in the final rule the criteria that define a modification to a flare. A flare is considered to be modified if: (1) Any piping from a refinery process unit or fuel gas system is newly connected to the flare or (2) the flare is physically altered to increase flow capacity. See section IV.I of this preamble for further explanation on the change in affected source from a fuel gas producing unit to the flare.

Petroleum refinery process units are subject to the final standards in 40 CFR part 60, subpart Ja if they meet the criteria under the reconstruction provisions, regardless of changes in emission rate. Reconstruction means the replacement of components of an existing facility such that (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards (40 CFR 60.15).

IV. Summary of Significant Comments and Responses

As previously noted, we received a total of 46 comments during the public comment periods associated with the proposed rule and NODA. These comments were received from refineries, industry trade associations, and consultants; State and local environmental and public health agencies; environmental groups; and members of the public. In response to these public comments, most of the cost and emission reduction impact estimates were recalculated, resulting in several changes to the final amendments and new standards. The major comments and our responses are

summarized in the following sections. A summary of the remainder of the comments received during the comment period and responses thereto can be found in the docket for the final amendments and new standards (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 costs and cost-effectiveness of the control options and re-evaluated our BDT determinations. In our BDT determinations, we took all relevant factors into account consistent with other Agency decisions. It is important to note that, due to the different health and welfare effects associated with different pollutants, the acceptable cost-effectiveness value of a control option is pollutant dependent. These pollutant-specific factors were considered along with other factors in our BDT determinations.

A. PM Limits for Fluid Catalytic Cracking Units

Comment: Several commenters opposed the proposed tightening of the FCCU PM standards relative to subpart J and the concurrent change in PM monitoring methods. Some commenters supported the co-proposal to keep the 1 lb/1,000 lb coke burn PM emission limit based on Method 5B and/or 5F; other commenters either did not oppose or supported the 0.5 lb/1,000 lb coke burn emission limit for new ''grassroots'' units, provided EPA demonstrates it is cost-effective and that the limit is based on EPA Method 5B or 5F (40 CFR part 60, Appendix A–3).

Commenters stated that EPA should only impose the more stringent emission limits on new construction because it is much more difficult and costly to meet the proposed emission limits for modified or reconstructed equipment. Commenters suggested that if EPA does include more stringent limits on modifications, it should exclude certain actions (like projects implemented to meet consent decree requirements) from the definition of a modification.

Several commenters suggested that the costs in Table 11 of the proposal preamble are significantly underestimated. Commenters contended that the single ''model plant'' approach used in EPA's cost analysis does not realistically consider important factors such as the inherent sulfur content of the feed, partial-burn versus full-burn regeneration, FCCU/regenerator size, and sources that are already well-controlled due to other regulations. Commenters asserted that the purchased equipment costs escalated from estimates that are 20 to 30 years old are underestimated. Several commenters provided estimates of costs and emission reductions for several actual projects, which they stated indicate that EPA's costs are significantly underestimated and that the proposed standards are much less cost-effective than presented by EPA.

A number of commenters asserted that the PM standards should be based on EPA Methods 5B or 5F (40 CFR part 60, Appendix A–3), and not on EPA Method 5 of Appendix A–3 to part 60. According to these commenters, the achievability of the proposed 0.5 lb/1,000 lb coke burn PM limit based on EPA Method 5 is questionable because there are inadequate data on FCCU using EPA Method 5, and controlling combined condensable and filterable PM to the 0.5 lb/1,000 lb coke burn level has not been demonstrated to be cost-effective.

On the other hand, several commenters stated that any PM limit must include condensable and filterable PM as condensable PM account for a large portion of refinery PM emissions and all condensable PM is PM that is less than 2.5 micrometers in diameter ($PM_{2.5}$), which has more adverse health impacts than larger particles; the commenters therefore agreed with the use of EPA Method 5 to determine filterable PM and requested that EPA consider Method 202 (40 CFR part 51, Appendix M) for condensable PM. Commenters also stated that the limits for PM and SO_2 in subpart Ja should apply to all new, reconstructed, and modified FCCU. One commenter recommended that a total PM limit (filterable and condensable) be set at 1 lb/1,000 coke burn; another stated that the total PM limit, including both filterable and condensable PM, should be 0.5 lb/1,000 lb coke burn, and EPA has not demonstrated that current BDT cannot achieve this limit. Finally, one commenter suggested that EPA should evaluate the cost of removing each pollutant (PM and SO_2) separately.

Response: In response to these comments, we have revised our analysis to consider each unique existing FCCU in the United States. By doing so, we fully account for plant size, partial-burn versus full-burn regeneration, existing control configuration, and specific consent decree requirements. (Details on the specific revisions to the analysis can be found in the docket.) With a revised analysis, we were able to more directly assess the impacts of process modifications or reconstruction of existing equipment. We also assessed the effects of PM and SO_2 standards separately in this analysis.

In our revised analysis, we considered three options for PM: (1) Maintain the existing subpart J standard of 1.0 lb/1,000 lb of coke burn-off (filterable PM as measured by Method 5B or 5F); (2) 0.5 lb/1,000 lb of coke burn-off (filterable PM as measured by Method 5B or 5F of Appendix A–3 to part 60); and (3) 0.5 lb/1,000 lb of coke burn-off (filterable PM as measured by Method 5 of Appendix A–3 to part 60). Similar to the analysis for the proposed standards, costs and emission reductions for each option were estimated as the increment between complying with subpart J and subpart Ja. We note that none of the available data suggest that a 0.5 lb/1,000 lb coke burn emission limit that includes both filterable and condensable PM as measured using EPA Method 202 is achievable in practice for the full range of facilities using BDT controls, so we disagree with the comments suggesting this level is appropriate to consider as an option for a total PM limit in this rulemaking.

Option 1 includes the same emissions and requirements for PM as the current 40 CFR part 60, subpart J, so it will achieve no additional emissions reductions. The PM limit in Option 2 is the same numerical limit that was proposed in subpart Ja, but the PM emissions are determined using Methods 5B and 5F (40 CFR part 60, Appendix A–3). These test methods are commonly used for PM tests of FCCU and are the methods that were used to generate a majority of the test data we reviewed. Option 3 is a limit of 0.5 lb/1,000 lb coke burn using Method 5 and is the performance level that was proposed for subpart Ja. The impacts of these three options for new FCCU are presented in Table 2 to this preamble; the impacts for modified and reconstructed FCCU are presented in Table 3 to this preamble.

TABLE 2.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR PM LIMITS CONSIDERED FOR NEW FLUID CATALYTIC CRACKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA[a]

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons PM/yr)	Cost effectiveness ($/ton)	
				Overall	Incremental
2	3,600	1,100	240	5,600	5,600
3	7,100	1,700	300	6,700	11,000

[a] PM cost-effectiveness calculated for PM-fine; 83.3 percent of the PM is PM-fine.

TABLE 3.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR PM LIMITS CONSIDERED FOR RECONSTRUCTED AND MODIFIED FLUID CATALYTIC CRACKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA[a]

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons PM/yr)	Cost effectiveness ($/ton)	
				Overall	Incremental
2	75,000	12,000	690	21,000	21,000
3	100,000	15,000	810	23,000	37,000

[a] PM cost-effectiveness calculated for PM-fine; 83.3 percent of the PM is PM-fine.

The available data and impacts for the options considered suggest that BDT for new FCCU is different than BDT for modified and reconstructed FCCU. For new FCCU, the costs for Option 2 are reasonable compared to the emission reduction achieved. The incremental cost between Option 2 and Option 3 of $11,000 per ton PM-fine would generally be considered reasonable, but there are uncertainties in the achievability of Option 3. The estimated PM emission reduction achieved by Option 3 compared to Option 2 equals the amount of sulfates and other condensable PM between 250 °F and 320 °F that would be measured by Method 5 but not Method 5B or 5F (40 CFR part 60, Appendix A–3). Additionally, available test data indicate that electrostatic precipitators (ESP) and wet scrubbers can reduce total filterable PM to 0.5 lb/1,000 lb of coke burn or less, as measured by Method 5-equivalent test methods. Although there were few test data points using Method 5-equivalent test methods, we concluded at proposal that both electrostatic precipitators and wet scrubbers can achieve this level of PM emissions. However, the data supporting Option 3 are not extensive, and it is unclear at this time whether a limit of 0.5 kg/Mg of coke burn as measured by Method 5 (40 CFR part 60, Appendix A–3) could be met by all configurations of FCCU. In addition, while the Agency supports reducing condensable PM emissions, the amount of condensable PM captured by Method 5 is small relative to methods that specifically target condensable PM, such as Method 202 (40 CFR part 51, Appendix M). We prefer to develop a single performance standard that considers all condensable PM rather than implementing phased standards targeting different fractions of condensable PM. Such an approach would be costly and inefficient. Therefore, we conclude that Option 2, control of PM emissions (as measured by Methods 5B and 5F of Appendix A–3 to part 60) to 0.5 lb/1,000 lb of coke burn or less, is BDT for newly constructed FCCU. This option achieves PM emission reductions of 240 tons per year (tons/yr) from a baseline of 910 tons/yr at a cost of $5,600 per ton of PM.

For modified and reconstructed FCCU, Option 1 is the baseline level of control established by the existing requirements of subpart J. It will achieve no additional cost or emission reduction. The overall costs and the incremental costs for Options 2 and 3 are reasonable compared to the PM emission reduction; however, as with new FCCU, the performance of Option 3 has not been demonstrated, so it is rejected. Most of the existing FCCU that could become subject to subpart Ja through modification or reconstruction are either already subject to subpart J or are covered by the consent decrees. The consent decrees are generally based on the existing subpart J. Industry has made significant investments in complying with these subpart J requirements which may be abandoned if they become subject to subpart Ja. In addition, the additional costs could create a disincentive to modernize FCCU to make them more energy efficient or to produce more refined products. For these reasons, we reject Option 2 for modified or reconstructed FCCU and conclude that control of PM emissions (as measured by Methods 5B and 5F of Appendix A–3 to part 60) is 1.0 lb/1,000 lb of coke burn or less is BDT for reconstructed and modified FCCU.

B. SO_2 Limits for Fluid Catalytic Cracking Units

Comment: Several commenters supported the co-proposal for modified and reconstructed FCCU to meet subpart J and not the 25 ppmv 365-day rolling average limit for SO_2. Commenters provided data to suggest that the retrofits of existing sources are not cost effective, particularly if catalyst additives cannot be used. The current subpart J includes three compliance options: (1) If using an add-on control device, reduce SO_2 emissions by at least 90 percent or to less than 50 ppmv; (2) if not using an add-on control device, limit sulfur oxides emissions (calculated as SO_2) to no more than 9.8 kg/Mg of coke burn-off; or (3) process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight. Several commenters objected to the elimination of the additional compliance options in the existing subpart J for subpart Ja because: (1) There are no data to show that the SO_2 limits proposed in subpart Ja are BDT for all FCCU regenerator configurations; (2) the three options are already established as BDT and, therefore, the CAA requires that EPA make them available; and (3) the substantial cost and other burdens for a reconstructed or modified FCCU already complying with one of the alternative options in subpart J to change to daily monitoring by Method 8 (40 CFR part 60, Appendix A–4) or to install CEMS were not addressed in the proposal.

One commenter supported the proposed SO_2 limit under Ja for new ''grassroots'' FCCU if the standard is demonstrated to be cost-effective.

Response: As acknowledged in the previous response on PM standards for FCCU, we completely revised our impacts analysis to evaluate SO_2 standards for every existing FCCU that may become subject to subpart Ja through modification or reconstruction. We did not have access to the inherent sulfur content of the feed for each FCCU so SO_2 emissions are still estimated using average emission factors relevant to the type of control device used for FCCU not subject to consent decree requirements. Nonetheless, we significantly revised the impact analysis to fully account for FCCU-specific throughput, existing controls, and consent decree requirements. (Details on the specific revisions to the analysis can be found in Docket ID No. EPA–HQ–OAR–2007–0011.) We evaluated two options: (1) Current subpart J, including all three compliance options; and (2) 50 ppmv SO_2 on a 7-day average and 25 ppmv on a 365-day average. Data are not available on which to base a more stringent control level.

Option 1 includes the same emissions and requirements as the current 40 CFR part 60, subpart J, so it will achieve no additional emissions reductions. Based on information provided by vendors and data submitted by petroleum refiners, Option 2 can be met with catalyst additives or a wet scrubber. Of 38 FCCU currently subject to a 50/25 ppmv SO_2 limit through consent decrees, 26 used wet scrubbers and 12 used catalyst additives or other (unspecified) techniques. Given the number of FCCU currently meeting the 50/25 ppmv SO_2 emission limit, we conclude that this limit is technically feasible.

The data in the record suggest that all systems with wet scrubbers can meet the 50/25 ppmv SO_2 emission limit with no additional cost. Further, based on information from the consent decrees, we believe that the owner or operator of an existing FCCU that does not already have a wet scrubber and is modified or reconstructed such that it becomes subject to subpart Ja can use catalyst additives to meet the 50/25 ppmv SO_2 emission limit. Therefore, the cost of Option 2 is calculated using catalyst additives as the method facilities choose for meeting the standard. We reject the idea that the 90 percent control efficiency, the 9.8 kg/Mg coke burn-off limit, or the 0.3 weight percent sulfur content alternatives are equivalent to the 50/25 ppmv SO_2 emission limit. Based on the original background document for the subpart J standards, these alternatives are expected to have outlet SO_2 concentrations of 200 to 400 ppmv. In reality the currently used wet scrubbers and catalyst additives achieve much higher SO_2 removal efficiencies and much lower outlet SO_2 concentrations. The impacts of these options are presented in Table 4 of this preamble.

TABLE 4.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR SO_2 LIMITS CONSIDERED FOR NEW, RECONSTRUCTED, AND MODIFIED FLUID CATALYTIC CRACKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons SO_2/yr)	Cost effectiveness ($/ton)	
				Overall	Incremental
2	0	3,000	4,400	700	700

Based on the data we reviewed to select the options and the estimated impacts of those options, we conclude that Option 2, control of SO_2 emissions to 25 ppmv or less averaged over 365 days and 50 ppmv or less averaged over 7 days, is technically feasible and cost-effective for new, reconstructed, and modified fluid catalytic cracking units. This option has no capital cost and achieves SO_2 emission reductions of 4,400 tons/yr from a baseline of 5,900 tons/yr at a cost of $700 per ton of SO_2. Therefore, we conclude that control of SO_2 emissions to 25 ppmv or less averaged over 365 days and 50 ppmv or less averaged over 7 days is BDT for new, reconstructed, or modified fluid catalytic cracking units.

C. NO_X Limit for Fluid Catalytic Cracking Units

Comment: Several commenters stated that they would support a NO_X limit of 80 ppmv for new sources only, provided a corrected impact analysis considers the different characteristics of FCCU and demonstrates that the NO_X limit for new sources is truly cost-effective. Commenters supported the co-proposal for modified and reconstructed FCCU to meet subpart J and not be subject to a NO_X emission limit. A few commenters provided cost data showing the cost of NO_X controls is high for modified and reconstructed units due to the high cost and space needed for add-on controls. The commenters also stated that a large number of existing FCCU in the U.S. are covered by consent decrees, so significant NO_X reductions have already been (or will soon be) achieved, and an additional incremental reduction to 20 or 40 ppmv over a 365-day average are not widely demonstrated and would not be cost-effective.

One commenter stated that selective noncatalytic reduction (SNCR), selective catalytic reduction (SCR), and catalyst additives have not been demonstrated over significant periods of operational life. Commenters also cited environmental side-effects, such as the generation of ammonia compounds that contribute to condensable PM emissions, as a reason not to require these types of controls. Commenters also asserted that technologies like flue gas recirculation or advanced burner design are typically only cost-effective for new units and may be technically infeasible for existing FCCU.

One commenter suggested that if a limit is necessary for modified or reconstructed FCCU, recent catalyst additive trials support an emission limit of approximately 150 ppmv on a 7-day rolling average; this limit would only be achievable if a 24-hour CO averaging time was provided since lowering NO_X tends to increase CO emissions in FCCU. The commenter noted that this limit is equivalent to the 0.15 pounds per million British thermal units (lb/MMBtu) standard for reconstructed and modified heaters and boilers in NSPS subpart Db.

Other commenters supported the inclusion of a NO_X limit for FCCU and opposed the co-proposal of no NO_X standard for modified and reconstructed FCCU. These commenters also recommended more stringent NO_X limits for FCCU and stated that 80 ppmv does not represent an adequate level of control given the evolution of emerging technologies. In addition, a BDT of 80 ppmv on 7-day rolling average does not look ''toward what may be fairly projected for the regulated future'' as required by Portland Cement I (486 F. 2d 375 at 384 (D.C. Cir. 1973)) and other court decisions. The commenters disagreed with the feasibility and cost analyses for modified and reconstructed FCCU and stated that FCCU under a consent decree are achieving lower levels than the 80 ppmv proposed by EPA. Given the significant hazards to

human health and the environment posed by NO_X emissions, the commenters recommended limits of 20 ppmv over a 365-day rolling average and 40 ppmv over a 7-day rolling average for all FCCU. The commenters noted that these limits have been successfully achieved under consent decrees and they are technically feasible on new units at reasonable costs without additional controls.

Response: As shown by the disparate comments received, many commenters suggest lower NO_X emission limits are achievable, while other commenters do not believe the proposed NO_X emission limits are cost-effective. While we do acknowledge that lower NO_X emission limits are technically achievable, the incremental cost of achieving these lower limits was high when we evaluated options for the proposed standards. Therefore, we concluded at proposal that 20 or 40 ppmv NO_X limits were not BDT. In our BDT assessment, we evaluated the various methods to meet alternative NO_X limits as BDT rather than identifying one technology. One of the reasons for this is that each technology has its own advantages and limitations. While non-platinum oxidation promoters and advanced oxidation controls do not achieve the same reduction in NO_X emissions as add-on control devices such as SCR, they do so without any significant secondary impacts. The added NO_X reduction of SCR and SNCR must be balanced with these secondary impacts. Part of the basis for selecting control methods to achieve an 80 ppmv NO_X emission limit as BDT included both cost and secondary impacts. This approach is necessary when conducting our BDT analysis, thus ensuring the best overall environmental benefit from the subpart Ja standards.

To ensure that we addressed the commenters' concerns, we re-evaluated the impacts for FCCU NO_X controls. We also collected additional data from continuous NO_X monitoring systems for a variety of FCCU NO_X control systems. These data suggest that as refiners gain more experience with the NO_X control systems (including catalyst additive improvements), NO_X control performance has improved over the past year or two. These data suggest that the achievable level for combustion controls and catalyst additives is 80 ppmv and the achievable level for add-on control systems is 20 ppmv. Therefore, we evaluated three outlet NO_X emission level options as part of the BDT determination: (1) 150 ppmv; (2) 80 ppmv; and (3) 20 ppmv. Each NO_X concentration is averaged over 7 days. To estimate impacts for Option 1, we estimated that some units have current NO_X emissions below 150 ppmv, and all other units can meet this level with combustion controls such as limiting excess O_2 or using non-platinum catalyst combustion promoters and other NO_X-reducing catalyst additives in a complete combustion catalyst regenerator or a combination of NO_X-reducing combustion promoters and catalyst additives with low-NO_X burners (LNB) in a CO boiler after a partial combustion catalyst regenerator. Data collected from FCCU complying with consent decrees show that Option 2 can also be met using combustion controls; therefore, we estimated impacts for Option 2 using a similar method as Option 1. The main difference is that a larger number of FCCU must use combustion controls to meet the emission limit (*i.e.*, the FCCU with current NO_X emissions between 150 and 80 ppmv would not need controls under Option 1 but would need controls under Option 2). Option 3 is the level at which we expect all units to install more costly control technology such as LoTOx™ or SCR. The estimated fifth-year emission reductions and costs for each option for new FCCU are summarized in Table 5 to this preamble; the impacts for modified and reconstructed FCCU are summarized in Table 6 to this preamble.

TABLE 5.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR NO_X LIMITS CONSIDERED FOR NEW FLUID CATALYTIC CRACKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons NO_X/yr)	Cost effectiveness ($/ton)	
				Overall	Incremental
1	860	320	370	880	880
2	1,200	640	860	750	650
3	12,000	3,600	1,400	2,600	5,800

TABLE 6.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR NO_X LIMITS CONSIDERED FOR MODIFIED AND RECONSTRUCTED FLUID CATALYTIC CRACKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons NO_X/yr)	Cost-effectiveness ($/ton)	
				Overall	Incremental
1	2,800	1,000	860	1,200	1,200
2	3,700	1,600	1,800	920	660
3	45,000	11,000	3,200	3,600	6,800

Options 1 and 2 provide cost-effective NO_X control with limited or no secondary impacts. The costs of Option 1 and Option 2 are commensurate with the emission reductions for new FCCU as well as modified and reconstructed FCCU. Option 3 would impose compliance costs that are not warranted for the emissions reductions that would be achieved, as shown by the incremental cost-effectiveness values of about $6,000 per ton of NO_X emission reduction between Option 2 and Option 3.

In evaluating these options, we also considered the secondary impacts. In addition to the direct PM impacts of SNCR and SCR, SCR and LoTOx™ units require additional electrical consumption. The increased energy consumption for Option 3 is 40,000 MW-hr/yr for new, modified, and reconstructed units. We also evaluated the secondary PM, SO_2, and NO_X emission impacts of the additional electrical consumption for Option 3. Based on the energy impacts, Option 3 will generate secondary emissions of PM, SO_2, and NO_X of 6, 150, and 57 tons/yr, respectively.

Based on the impacts shown in Table 5 and Table 6, and taking secondary impacts into account, we conclude that BDT is Option 2, a NO_X emission limit of 80 ppmv, for all affected FCCU. For new FCCU, this option achieves NO_X emission reductions of 860 tons/yr from a baseline of 1,500 tons/yr at a cost of $750 per ton of NO_X. For modified and reconstructed FCCU, this option achieves NO_X emission reductions of 1,800 tons/yr from a baseline of 3,600 tons/yr at a cost of $920 per ton of NO_X.

D. PM and SO_2 Limits for Fluid Coking Units

Comment: Several commenters stated that EPA's proposed standards for FCU under subpart Ja are inappropriate and not cost-effective. Commenters asserted that based on the significant differences between FCU and FCCU operations, a separate BDT determination is needed for FCCU and FCU. Commenters stated that an FCU has higher particulate loading; a heavier feedstock that typically contains a higher concentration of sulfur, increasing the SO_2 and sulfur trioxide (SO_3) emissions; and a wider range of feedstocks with considerable variability in the nitrogen content.

The commenters noted that the impacts analysis performed for the FCU has shortcomings similar to those in the impacts analysis for FCCU (*e.g.*, the analysis did not properly consider the additional costs and technical difficulties of meeting the proposed emission limits for modified or reconstructed sources, existing units are already controlled and thus the emission reductions have already been achieved). One commenter provided site-specific engineering cost estimates to indicate that the PM controls are much less cost-effective than EPA estimates. The commenter requested that EPA consider instances when wastewater limitations require regenerative wet scrubbers and amend the impact estimates accordingly. One commenter stated that a newly installed regenerative wet scrubber system on an existing FCU could not meet the proposed Ja PM standards.

Response: As described in the preamble to the proposed standards, the original analysis assumed that one of the larger existing FCU will become a modified or reconstructed source in the next 5 years. However, the two larger FCU in the U.S. are both subject to consent decrees: one has installed controls and the other is in the process of installing controls. The remaining two FCU are significantly smaller than the original model FCU; therefore, a new analysis was conducted using a smaller model FCU indicative of the size of the two remaining FCU that are not subject to consent decree requirements. In our new analysis, this FCU has approximately one-half the sulfur content as the larger FCU for which we have data, based on information received regarding the variability in sulfur content across different FCU in the public comments.

In addition to revising our impact analysis, we also collected additional source test data from the one FCU operating a newly installed wet scrubber system to better characterize the control system's performance. At proposal, we had one FCU source test from this source, which suggested that the FCU wet scrubber could meet a PM limit of 0.5 lb/1,000 coke burn. However, following proposal, we received an additional performance test for this same FCU wet scrubber with an emission rate between 0.5 and 1.0 lb/1,000 lb coke burn. There was no indication of unusual performance during either of these two tests, so we conclude that these tests demonstrate the variability of the emission source and control system. Based on the available data, therefore, we conclude that an appropriate PM performance level to consider for a BDT analysis is 1.0 lb/1,000 lb coke burn using EPA Method 5B (40 CFR part 60, Appendix A–3) for a FCU with a wet scrubber. We also conclude that the PM emission limit initially proposed for FCU had not been adequately demonstrated as an emission limit with which one must comply at all times.

Using our revised model FCU and based on the additional source test data, we re-evaluated BDT for PM and SO_2 emissions from FCU based on two options: (1) No new standards, or current subpart J; and (2) a PM limit of 1.0 lb/1,000 lb coke burn (as measured using Methods 5B and 5F of 40 CFR part 60, Appendix A–3), a short-term SO_2 limit of 50 ppmv averaged over 7 days, and a long-term SO_2 limit of 25 ppmv averaged over 365 days. Unlike the FCCU, catalyst additives cannot be used in a FCU to reduce SO_2, so a wet scrubber is the most likely technology (and the one demonstrated technology) that would be used to meet the PM and SO_2 limits of Option 2. Therefore, we estimated costs for an enhanced wet scrubber to meet both the PM and SO_2 limits. The resulting emission reductions and costs for both of the options are shown in Table 7 of this preamble.

TABLE 7.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR PM AND SO_2 LIMITS CONSIDERED FOR FLUID COKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons PM/yr)	Emission reduction (tons SO_2/yr)	Cost effectiveness ($/ton PM and SO_2)
2	10,000	3,200	1,000	5,900	460
2a	100,000	18,600	1,000	5,900	2,700

One commenter indicated that we should consider the costs of a regenerative wet scrubber. This type of system is not needed in most applications; however, in the event such a system were needed, we estimated the cost of a regenerative wet scrubber to meet Option 2. The results of this analysis are also provided in Table 7 as Option 2a. As presented in Table 7, even under the most conservative assumptions the costs associated with the PM and SO_2 emission reductions are reasonable.

Based on the available technology and the costs presented in Table 7 to this preamble, we conclude that BDT is Option 2, which requires technology that reduces PM emissions to 1.0 lb/1,000 of coke burn and reduces SO_2 emissions to 50 ppmv averaged over 7 days and 25 ppmv averaged over 365 days. This option achieves PM emission reductions of 1,000 tons/yr from a baseline of 1,100 tons/yr and SO_2 emission reductions of 5,900 tons/yr from a baseline of 6,100 tons/yr at a cost of $460 per ton of PM and SO_2 combined.

E. NO_X Limit for Fluid Coking Units

Comment: A number of commenters opposed the co-proposal of no NO_X standard for FCU, and some disagreed with EPA's 80 ppmv NO_X limit for FCU. These commenters recommended limits

of 20 ppmv as a 365-day rolling average and 40 ppmv as a 7-day rolling average for FCU, as has been successfully achieved under consent decrees. The commenters noted that these limits are achievable on new units without additional controls.

One commenter supported the co-proposal that no new NO_X standard be established for FCU.

Response: Similar to the revised analysis for PM and SO_2 impacts, we re-evaluated BDT for the FCU NO_X controls for a smaller modified or reconstructed FCU. We evaluated three options: (1) No new standards, which is the current subpart J; (2) outlet NO_X concentration of 80 ppmv; and (3) outlet NO_X concentration of 20 ppmv. Similar to the analysis for FCCU NO_X and depending on the baseline emissions for the FCU, we anticipate that Option 2 can be met using combustion controls and Option 3 will require add-on control technology. The results of this analysis are shown in Table 8 to this preamble.

TABLE 8.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR NO_X LIMITS CONSIDERED FOR FLUID COKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission/ reduction (tons NO_X /yr)	Cost-effectiveness ($/ton)	
				Overall	Incremental
2	3,700	850	660	1,300	1,300
3	6,000	1,300	750	1,700	5,000

The costs for Option 1 and Option 2 are commensurate with the emission reductions, but the incremental impacts for Option 3 are not reasonable, as shown in Table 8. Option 3 achieves an additional 90 tons per year NO_X reduction, but the incremental costs between options 2 and 3 of achieving this reduction is $5,000 per ton of NO_X removed. The cost of achieving this 12 percent additional emission reduction nearly triples the total annualized cost of operating the controls. As with FCCU, the add-on NO_X controls for FCU have increased energy requirements and secondary air pollution impacts. Based on these projected impacts, we support our original determination that BDT is Option 2, or technology needed to meet an outlet NO_X concentration of 80 ppmv or less. This option achieves NO_X emission reductions of 660 tons/yr from a baseline of 800 tons/yr at a cost of $1,300 per ton of NO_X.

F. SO_2 Limit for Small Sulfur Recovery Plants

Comment: One commenter stated that no new requirements should be added for SRP less than 20 LTD (small SRP) because the controls are not cost-effective. The commenter provided data on tail gas treatment projects but noted that these costs are for large SRP, and controls for small SRP will be less cost-effective. Several commenters noted that if EPA does establish standards for small SRP, the monitoring and compliance evaluation methods for the 99 percent control standard are not clearly specified in the rule and could create difficulties in documenting compliance for small Claus plants. Therefore, the small SRP should be allowed to comply with the 250 ppmv SO_2 emission limit provided to large SRP. One commenter suggested that non-Claus units should be subject to a 95 percent recovery efficiency standard.

Response: To ensure that we addressed the commenters' concerns regarding cost-effectiveness, we re-evaluated the impacts for small SRP. We adjusted our cost estimates upward based on capital costs provided by industry representatives. We evaluated three SO_2 control options as part of the BDT determination for small SRP: (1) No new standards, or current subpart J; (2) 99 percent sulfur recovery; and (3) 99.9 percent sulfur recovery. As noted in the preamble to the proposed standards (section V.D), the 99 percent and 99.9 percent recovery levels are achievable for SRP of all sizes by various types of SRP or tail gas treatments.

The estimated fifth-year emission reductions and costs for new SRP are summarized in Table 9 to this preamble; the impacts for modified and reconstructed SRP are summarized in Table 10 to this preamble. These values reflect the impacts only for small SRP; there are no additional cost impacts for large Claus units because they would already have to comply with the existing standards in subpart J.

TABLE 9.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR SO_2 LIMITS CONSIDERED FOR NEW SMALL SULFUR RECOVERY PLANTS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons SO_2/yr)	Cost-effectiveness ($/ton)	
				Overall	Incremental
2	130	63	42	1,500	1,500
3	590	230	52	4,500	18,000

TABLE 10.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR SO_2 LIMITS CONSIDERED FOR MODIFIED AND RECONSTRUCTED SMALL SULFUR RECOVERY PLANTS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons SO_2/yr)	Cost-effectiveness ($/ton)	
				Overall	Incremental
2	1,600	670	380	1,800	1,800

TABLE 10.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR SO_2 LIMITS CONSIDERED FOR MODIFIED AND RECONSTRUCTED SMALL SULFUR RECOVERY PLANTS SUBJECT TO 40 CFR PART 60, SUBPART JA—Continued

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons SO_2/yr)	Cost-effectiveness ($/ton)	
				Overall	Incremental
3	7,800	2,600	470	5,700	23,000

The costs for Option 2 are reasonable considering the emission reductions achieved, but the incremental impacts shown in Table 9 and Table 10 for Option 3 are beyond the costs that the Agency believes are reasonable for these small units to achieve an additional 100 tons per year of SO_2 emission reductions. The additional equipment needed to achieve these reductions quadruples the capital costs. These smaller units would also generally be found at small refineries. Based on these projected impacts and available performance data, we support our original determination that BDT is Option 2, or 99 percent sulfur recovery. For new SRP, this option achieves SO_2 emission reductions of 42 tons/yr from a baseline of 150 tons/yr at a cost of $1,500 per ton of SO_2. For modified and reconstructed SRP, this option achieves SO_2 emission reductions of 380 tons/yr from a baseline of 1,400 tons/yr at a cost of $1,800 per ton of SO_2.

We note that we are also revising the format of the standard in response to public comments in terms of sulfur outlet concentrations. Based on the Option 2 BDT selection of a recovery efficiency of 99 percent, the emission limit for small SRP is either 2,500 ppmv SO_2 or 3,000 ppmv reduced sulfur compounds and 100 ppmv of H_2S, both of which are determined on a dry basis, corrected to 0 percent O_2.

G. NO_X Limit for Process Heaters

Comment: Several commenters stated that the 80 ppmv NO_X limit for process heaters is not stringent enough. Commenters stated that considering recent settlement negotiations and regulation development, NO_X emissions reductions well below 80 ppmv can be achieved cost effectively. The commenters stated that NO_X emissions of less than 40 ppmv at 0 percent O_2 are achievable with combustion modifications such as LNB, ultra low—NO_X burners (ULNB), and flue gas recirculation technologies; post-combustion controls such as SCR, SNCR, and LoTOx™ achieve NO_X reductions an order of magnitude below those from combustion modifications. The commenters noted that Bay Area Air Quality Management District (BAAQMD) Regulation 9, Rule 10, requires process heaters to meet a 0.033 lb/MMBtu NO_X limit (roughly 32 ppmv NO_X at 0 percent oxygen). One commenter stated that 30 ppmv has been demonstrated under consent decrees to be an achievable level and ample technology exists. The commenters also noted that 7 to 10 ppmv NO_X limits (at 3 percent oxygen) have been achieved in practice. One commenter stated that NSPS subparts J and Ja should impose NO_X emission limits on all fuel gas combustion devices that are at least as stringent as the most stringent consent decree. Some consent decrees require next generation ULNB designed to achieve NO_X emissions rates of 0.012 to 0.020 lb/MMBtu (12 to 20 ppmv NO_X at 0 percent oxygen). Commenters recommending more stringent requirements suggested limits ranging from 7 ppmv NO_X (at 3 percent oxygen) to 30 ppmv for new process heaters fueled by refinery fuel gas.

Other commenters stated that alternative monitoring options should be provided to small fuel gas combustion devices due to the high costs of CEMS relative to the emissions from the small devices. One commenter suggested an exemption from the fuel gas monitoring requirements for process heaters less than 50 MMBtu/hr. Another commenter recommended an exemption from the fuel gas monitoring requirements for process heaters less than 40 MMBtu/hr as used by South Coast Air Quality Management District (SCAQMD).

Response: We revisited the BDT determination based on the public comments and revised the methodology used to calculate the cost and emission reduction impacts for the proposed standards. We evaluated three options as part of the BDT determination. Each option consists of a potential NO_X emission limit and applicability based on process heater size. These differ slightly from the proposal options based o n commenter suggestions. Option 1 would limit NO_X emissions to 80 ppmv or less for all process heaters with a capacity greater than 20 MMBtu/hr (the proposed standards). Option 2 would limit NO_X emissions to 40 ppmv or less for all process heaters with a capacity greater than 40 MMBtu/hr. This option is similar to many consent decrees that set an emission limit of 0.040 lb/MMBtu (roughly 40 ppmv NO_X at 0 percent oxygen) for process heaters greater than 40 MMBtu/hr. Option 3 would limit NO_X emissions to 20 ppmv or less for all process heaters with a capacity greater than 40 MMBtu/hr. In each option, the NO_X concentration is based on a 24-hour rolling average.

The estimated fifth-year emission reductions and costs for each option for new process heaters are summarized in Table 11 of this preamble; impacts for modified and reconstructed process heaters are summarized in Table 12 of this preamble. Similar to the proposal analysis, we considered LNB, ULNB, flue gas recirculation, SCR, SNCR, and LoTOx™ as feasible technologies. We believe that nearly all process heaters at refineries that will become subject to subpart Ja can meet Option 1 or Option 2 using combustion controls (LNB or ULNB). Most process heaters would need to use more efficient control technologies, such as LoTOx™ or SCR, to meet the NO_X concentration limit in Option 3. Per commenters' request to focus on the larger units, Options 2 and 3 do not include process heaters between 20 MMBtu/hr and 40 MMBtu/hr. We evaluated the cost-effectiveness of NO_X control options for these units to achieve the proposed standard of 80 ppmv. For these process heaters with smaller capacities we found the cost-effectiveness ranged from $3,500/ton to $4,200/ton of NO_X reduced, which was determined not to be reasonable for these small heaters, which would primarily be located at small refineries.

TABLE 11.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR NO_X LIMITS CONSIDERED FOR NEW PROCESS HEATERS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons NO_X/yr)	Cost-effectiveness ($/ton)	
				Overall	Incremental
1	9,000	7,300	4,800	1,500	1,500
2	9,000	7,500	5,200	1,400	500
3	110,000	30,000	5,900	5,100	37,000

TABLE 12.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR NO_X LIMITS CONSIDERED FOR MODIFIED AND RECONSTRUCTED PROCESS HEATERS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons NO_X/yr)	Cost-effectiveness ($/ton)	
				Overall	Incremental
1	12,000	4,000	2,100	1,900	1,900
2	14,000	4,300	2,200	1,900	2,100
3	64,000	15,000	2,500	5,900	39,000

Based on the impacts in Table 11 and Table 12, the costs of Options 1 and 2 are reasonable compared to the emission reductions. The incremental cost between Options 2 and 3 of almost $40,000/ton of NO_X is not commensurate with the additional 1,000 tons of emission reduction achieved for new and modified or reconstructed process heaters. Moreover, the capital costs of Option 3 are about $150 million greater than the capital costs for Option 2, which are only $23 million. Therefore, we conclude that BDT for process heaters greater than 40 MMBtu/hr is technology that achieves an outlet NO_X concentration of 40 ppmv or less, or Option 2. For new process heaters, this option achieves NO_X emission reductions of 5,200 tons/yr from a baseline of 7,500 tons/yr at a cost of $1,400 per ton of NO_X. For modified and reconstructed process heaters, this option achieves NO_X emission reductions of 2,200 tons/yr from a baseline of 3,200 tons/yr at a cost of $1,900 per ton of NO_X. Although we agree that lower NO_X concentrations are achievable, we determined that the incremental cost to achieve these lower NO_X concentrations was not reasonable.

H. Fuel Gas Combustion Devices

Comment: Several commenters contended that the proposed standards for fuel gas combustion devices were not stringent enough; EPA should ensure that the best demonstrated emission control technologies are installed as the industry is modernized. Given the significant hazards to human health and the environment posed by SO_2 emissions, the commenters suggested that the 365-day average limits should be 40 ppmv TRS and 5 ppmv SO_2. The commenters also recommended that EPA tighten the 3-hour concentration limit to 100 ppmv TRS. On the other hand, another commenter contended that although amine treatment applications for product gases can achieve H_2S concentrations of 1 to 5 ppmv, a tighter standard is not BDT for refinery fuel gas.

Several commenters objected to the addition of the 60 ppmv H_2S and 8 ppmv SO_2 limits (365-day rolling average) in the proposed subpart Ja standards for fuel gas combustion devices because they are infeasible and/or not cost-effective. According to commenters, EPA erroneously assumed that the additional reductions could be achieved with existing equipment. Although this may be true in some cases, commenters asserted that some refineries would need to add additional amine adsorber/regenerator capacity and some may also need to add additional sulfur recovery capacity (*e.g.*, an additional Claus train and tail gas treatment unit). One commenter requested an exemption be provided for refineries that cannot meet the tighter long-term standard by simply increasing their amine circulation rates. One commenter stated that there will be little incremental environmental benefit from the long-term limit, and it unnecessarily penalizes refineries that designed their amine systems to treat to levels near the proposed annual standard. The commenters provided cost data for examples of projects requiring new amine adsorption units to show that the proposed standards are not cost-effective.

A number of commenters particularly opposed the proposed revision to include TRS limits for fuel gas produced from coking units or any fuel gas mixed with fuel gas produced from coking units. One commenter noted that some State and local agencies have specific TRS standards, but these requirements were not based on a BDT assessment. According to commenters, EPA has included no technical basis for the achievability of the TRS fuel gas standard or explanation of why control of TRS is limited to fuel gas generated by coking units. The commenters recommended that EPA postpone adoption of a TRS limit until it has gathered and evaluated adequate data to conclude that the limit is technically feasible and cost effective.

Commenters stated that EPA did not address the cost-effectiveness and non-air quality impacts of the TRS standards and did not define BDT for the removal of TRS. One commenter stated that without an established *de minimis* level, an entire fuel gas system could be subject to the TRS limits if any amount of coker gas enters the fuel gas system. Amine scrubbing systems are selective to H_2S and are not suitable to other TRS compounds such as mercaptans, according to the commenters. Commenters stated that the non-H_2S TRS compounds are not amenable to amine treating and there is no technology readily in-place at refineries for reducing non-H_2S TRS compounds. Therefore, according to the commenters, removing these other TRS compounds would require significant capital outlay for new equipment, costs that were not considered in the impacts analysis.

One commenter provided an example of a treatment system installed to meet a facility-wide fuel gas total sulfur standard of 40 ppmv; the commenter estimated the capital cost of the entire system to be $150 million. The commenter also indicated that low-BTU gas from flexicoking units would need to be specially treated at a capital cost of $61 million to achieve a total sulfur content of less than 150 ppmv, and the treatment would increase energy consumption, resulting in increases in NO_X and CO emissions. Another commenter provided an order-of-magnitude engineering estimate of $50 million to treat TRS down to 45 ppmv (long-term average). Based on one commenter's experience with a new fuel gas treating facility, non-acidic TRS cannot be treated down to the proposed levels utilizing Merox-amine treatment. A cost-effective solution could be natural gas blending at the affected combustion device; however, this option has the negative effect of reducing the production of refinery fuel gas and therefore reducing the refinery's capacity for making gasoline.

Several commenters stated that the original BDT determination was based on amine scrubbing of H_2S and not on SO_2; the SO_2 standard was simply a compliance option that was calculated to be equivalent to the H_2S concentration limit at 0 percent excess air. They also asserted that EPA cannot use the SO_2 option as a basis for the TRS standard because the SO_2 option is not BDT. On the other hand, one commenter requested that EPA clarify the fuel gas standards in subpart J to expressly indicate that the 20 ppmv SO_2 limit is a valid compliance option (instead of including it only in the monitoring section). According to the commenter, focus has been on H_2S due to the structure of the requirements of subpart J and permits rarely require that combustion sources demonstrate compliance with the 20 ppmv SO_2 limit. The commenter stated that refiners clearly should be allowed to comply with the broader, more comprehensive SO_2 limit.

A few commenters noted that, as H_2S is part of TRS, the TRS standard is even more stringent than the H_2S standard. One commenter recommended that no change in the fuel gas standards be made or that the standards focus on H_2S only with an alternative emission limit for SO_2. One commenter stated that EPA developed the 160 ppmv H_2S standard to be more stringent than the 20 ppmv SO_2 standard specifically because H_2S did not represent all of the sulfur in the fuel gas. Commenters stated that using an F-factor approach (Method 19, 40 CFR part 60, Appendix A–7), the TRS limit that is equivalent to the 20 ppmv SO_2 emission limit is 260 ppmv and the TRS limit that is equivalent to the 8 ppmv SO_2 emission limit is 104 ppmv.

Response: We initially concluded that fuel gas generated by the coking unit was mixed with other fuel gases that were mostly H_2S and that increasing the amine circulation rate would result in additional H_2S removal that could be used to meet the proposed standard. However, based on a review of the available data, non-H_2S sulfur content in coker fuel gas may be 300 to 500 ppmv. At these levels, specific treatment to reduce these other sulfur compounds would be needed. As indicated by one commenter, a plant-wide total sulfur limit of 40 ppmv has been achieved in practice in at least one refinery using a treatment train consisting of a Merox system, sponge oil absorbers, MEA absorbers, and caustic wash towers. Therefore, total sulfur fuel gas treatment methods are demonstrated. We evaluated the cost of this treatment based on information provided in the public comments.

Based on the public comments and additional data, we revisited the BDT determination and assessed three options for increasing SO_2 control of fuel gas combustion devices: (1) 20 ppmv SO_2 or 162 ppmv H_2S averaged over 3 hours; (2) Option 1 plus 8 ppmv SO_2 or 60 ppmv H_2S averaged over 365 days; and (3) a compliance option of 162 ppmv TRS averaged over 3 hours and 60 ppmv TRS averaged over 365 days for fuel gas combustion devices combusting fuel gas generated by a coking unit and Option 2 for combustion devices combusting fuel gas not generated by a coking unit. Option 1 includes the same limits that are in subpart J, so there are no additional costs or emission reductions beyond those expected from the application of subpart J. To address the commenters' concerns that not all facilities have available amine capacity to ensure compliance with the new long-term limits, we revised our proposal analysis to include additional costs for the estimated 10 percent of the affected facilities that would increase their amine capacity to achieve Option 2. We estimated costs for a separate treatment train that can treat TRS for Option 3 because, based on the public comments received, we have concluded that amine treatment systems are not effective for non-H_2S components of TRS. The estimated fifth-year impacts of each of these options for new fuel gas combustion devices are presented in Table 13 of this preamble; the impacts for modified and reconstructed fuel gas combustion devices are presented in Table 14 of this preamble.

TABLE 13.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR SO_2 LIMITS CONSIDERED FOR NEW FUEL GAS COMBUSTION DEVICES SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons SO_2/yr)	Cost-effectiveness ($/ton)	
				Overall	Incremental
2	1,200	720	510	1,400	1,400
3	100,000	13,000	770	17,000	47,000

TABLE 14.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR SO_2 LIMITS CONSIDERED FOR MODIFIED AND RECONSTRUCTED FUEL GAS COMBUSTION DEVICES SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons SO_2/yr)	Cost-effectiveness ($/ton)	
				Overall	Incremental
2	33,000	11,000	4,700	2,400	2,400
3	1,700,000	200,000	7,600	26,000	63,000

Overall costs for Options 1 and 2 are reasonable compared to the emission reduction achieved for new, modified and reconstructed fuel gas combustion devices. We further evaluated the incremental costs and reductions between the three options and found that they were reasonable for Options 1 and 2, while the incremental cost for Option 3 is not. While Option 3 provides significant additional SO_2 emission reductions, the additional capital cost of $1.7 billion is high and could pose a significant barrier to future refinery upgrades and expansions. Based on these impacts and consideration of current operating practices, we conclude that BDT is use of technology that reduces the emissions from affected fuel gas combustion devices to 20 ppmv SO_2 or 162 ppmv H_2S averaged over 3 hours and 8 ppmv SO_2 or 60 ppmv H_2S averaged over 365 days, or Option 2. For new fuel gas combustion devices, this option achieves SO_2 emission reductions of 510 tons/yr from a baseline of 1,000 tons/yr at a cost of $1,400 per ton of SO_2. For modified and reconstructed fuel gas combustion devices, this option achieves SO_2 emission reductions of 4,700 tons/yr from a baseline of 10,000 tons/yr at a cost of $2,400 per ton of SO_2.

We note that although we have determined that Option 3 is not BDT and we will not limit the amount of SO_2 emissions from combustion of sulfur compounds other than H_2S in subpart Ja, we plan to continue to work with the industry to understand the magnitude of these SO_2 emissions and to identify technologies that can be cost effectively applied to reduce the emissions. We have learned through this process that the SO_2 emissions from combustion of TRS in coker gas are generally not reflected in emission inventories and we plan to explore this issue in greater detail in the future to determine where SO_2 emissions are underestimated and the best way to correct the inventories.

Comment: Several commenters stated that it is impossible for a refinery owner or operator to specify, acquire, install, and calibrate a continuous monitoring system within 15 days of a change that increases the H_2S concentration such that an exempt stream is no longer exempt. One commenter suggested quarterly stain tube sampling for 1 year prior to revoking an exemption from monitoring to confirm the change is permanent. The commenter suggested that after 1 year of confirmation, an additional 12 months be provided to specify, acquire, install, and calibrate the continuous monitoring system. One commenter suggested 1 year be provided for installing a CEMS, while another commenter suggested 180 days be provided (with an allowance for an additional extension) for installing a CEMS, rather than the 15 days proposed.

Response: We believe that in most cases, the process change would be a deliberate, planned act and that the potential consequences of this deliberate change would be evaluated. That is, before the equipment is modified, the refinery owner or operator is expected to assess the impacts of this change on the exempted fuel gas stream. If the change is expected to increase the sulfur content of the fuel gas, than the owner or operator can plan to install the required CEMS when modifying the process. We recognize that some process changes may have unexpected consequences, and a modification that was not expected to increase the sulfur content of the fuel gas can result in an increase in sulfur content. In this case, it may be impossible to install the required CEMS within 15 days. However, quarterly sampling does not provide any basis by which the refinery owner or operator can demonstrate compliance with the H_2S concentration standard. Instead, we have added provisions that require an owner or operator to install a CEMS as soon as practicable and no later than 180 days after a change that makes the stream no longer exempt. Between the process change and the time a CEMS is installed, the owner or operator must conduct daily stain tube sampling to demonstrate compliance with the H_2S concentration standard. During this time, a single daily sample exceeding 162 ppmv must be reported as an exceedance of the 3-hour H_2S concentration limit and a rolling 365-day average concentration must be determined. A daily average H_2S concentration of 5 ppmv is to be used for the days prior to the process change for the previously exempt stream in calculating the rolling 365-day average concentration.

I. Flaring of Refinery Fuel Gas

Comment: Several commenters supported the proposed work practice standards to eliminate routine flaring and develop startup, shutdown, and malfunction (SSM) plans; the commenters opposed the co-proposal of no standards. One commenter supported the determination that elimination of routine flaring is BDT, citing reductions in hydrocarbon, NO_X, SO_2, and carbon dioxide (CO_2) emissions. One commenter stated that both subparts J and Ja should explicitly require that flaring be used only as a last resort in unusual circumstances, such as emergencies, and not on a routine basis. Commenters asserted that monitoring on an ongoing basis is needed to verify that no flaring of nonexempt gases occurs. Commenters stated that subpart Ja should also require refiners to install a flare gas recovery system, although such requirements should not preclude monitoring requirements. One commenter stated that the NSPS should require a SSM plan to eliminate venting or flaring during such planned start-up, shutdown, and maintenance activities and explicitly prohibit venting or flaring during these planned activities; proper operation and maintenance practices should completely eliminate the need to use flares during these activities. One commenter noted that those refineries that have evaluated their startup and shutdown procedures to reduce or eliminate direct venting or flaring during planned startup and shutdown events have demonstrated the best technology; therefore, their actions represent BDT and should be adopted in the NSPS. The commenters also supported conducting a root cause analysis (RCA) in the event of flaring and other venting releases of 500 lb/day SO_2.

A number of commenters generally supported the intent to reduce flaring and the idea of SSM plans to address flaring during planned startups and shutdowns (one commenter also included combustion of high sulfur-containing fuel gases during a malfunction), flare management plans, and RCA for flare events in excess of 500 lb/day. However, they opposed the work practice standard for elimination of routine flaring and the proposed creation of fuel gas producing units for subpart Ja. The commenters stated that the definition of ''fuel gas producing unit'' is overly broad, making it difficult to determine what constitutes a modification or reconstruction, and the proposed work practice standard for these units is infeasible, unnecessary, and not cost-effective. Facility operators and regulators would have difficulty discerning if a flaring event was caused by an affected fuel gas producing unit or a unit not subject to the standard. One commenter indicated that there is no *de minimis* level by which units that produce insignificant quantities of fuel gas can be excluded from the extensive work practice standards.

Commenters recommended that the affected source be the flare which is already subject to the standard as a fuel gas combustion device. The commenters suggested that for each affected flare, the facility would develop a written Flare Management Plan designed to minimize

flaring of fuel gas during all periods of operation. This plan, along with the RCA, would ensure that all flaring events with potential excess emissions will be minimized. One commenter noted that EPA could require a flare management plan for any flare tied to a fuel gas system that has an affected fuel gas combustion device as a better alternative to ''fuel gas producing units.'' One commenter noted that an exemption from the notification requirements for modified or reconstructed units could be provided as an incentive for early adoption of the flare management plan; another commenter suggested that regulatory incentives such as exemptions from monitoring and developing flare management plans should be provided for facilities that have installed flare gas recovery systems. One commenter supported this type of requirement for flares currently subject to subpart J, assuming a minimum of 9 months is provided for plan development and implementation. On the other hand, one commenter noted that the definitions of the affected facility under subparts J and Ja are different and recommended that the distinction be made stronger so that it is clear that existing process unit facilities are ''grandfathered'' and exempt from the flaring minimization standards.

One commenter suggested that the work practices language should be clarified to indicate that routing offgas to the flare system would be acceptable if the system was equipped with a flare gas recovery system. The prohibition should be specific to the flare itself as some flare systems are equipped with recovery compressors, the use of which should be encouraged rather than discouraged.

Commenters stressed the need for flares as safety devices; any flare minimization program must not interfere with the ability of the refinery owner or operator to use flares for safety reasons. The commenters stated that ''routine'' flaring cannot be adequately defined in practice; therefore, restrictions on ''routine'' flaring will lead to unsafe operations in attempts to avoid enforcement actions. The commenters requested that EPA include language in the regulation, consistent with the preamble discussion, that: ''Nothing in this rule should be construed to compromise refinery operations and practices with regard to safety.''

One commenter indicated that the proposed work practice standards for ''no routine flaring'' interfere with flare minimization plans implemented in response to consent decrees. The proposed work practice standard could be interpreted as prohibiting flaring during start-up and shutdown, and EPA has not determined this to be BDT. The commenter stated that the BAAQMD analysis applies to eliminating flaring during normal operation [similar to proposed § 60.103a(b)], not during start-up and shutdown as in proposed § 60.103a(a). The commenter provided cost estimates for one refinery to install a recovery system to eliminate flaring during start-up and shutdowns; the costs ranged from $200,000 to $800,000 per ton of VOC reduced and higher for other criteria pollutants. Therefore, they contend § 60.103a(a) should clearly exclude start-up and shutdown gases.

A few commenters provided overall project costs for flare gas recovery projects indicating the annual costs are higher than those in the analysis supporting the proposed work practice. One commenter stated that EPA underestimated the cost of flare gas recovery systems and, given the uncertainty in emission reductions, contended that flare gas recovery systems for the no-flaring option are not cost-effective within the NSPS context. The commenter also stated that the regulation should include maintenance provisions for flare gas recovery systems (that allow flaring) during times of routine and non-routine maintenance, as no redundant capacity within the flare system exists.

A number of commenters provided an alternative to EPA's proposed work practice standards. The suggestions included a 500 lb/day SO_2 standard tied with a flare management plan as an alternative compliance option (to the H_2S concentration limit) for flares. The commenters recommended that this alternative compliance option be provided in both subparts J and Ja and noted that it could be used as an incentive for the flare management plan to cover all flares. One commenter also noted that these requirements should be applicable to flares that receive process gas, fuel gas, or process upset gas; they should not be applicable to flares used solely as an air pollution control device, such as a flare used exclusively to control emissions from a gasoline loading rack. Another commenter clarified that if the refinery elects to comply with this alternative for any flare, all flares at the refinery would need a flare management plan. The commenter noted that EPA could choose to set the 500 lb/day SO_2 limit as a total for all flares for which the alternative compliance option is chosen (*i.e.*, if the alternative compliance option is selected for two flares at a refinery, the total emissions from both flares would be limited to 500 lb/day).

Response: Although commenters suggested that certain provisions be made applicable to facilities subject to subpart J, the following provisions are only applicable to facilities subject to subpart Ja as CAA section 111 provides that new requirements apply only to new sources. We considered these comments and agree that the standards are more straightforward when the affected facility is defined as the flare. Therefore, we have eliminated ''fuel gas producing units'' as an affected facility in this final rule, and we specifically define a flare as a subset of fuel gas combustion device, which is an affected facility in this final rule. A ''flare'' means ''an open-flame fuel gas combustion device used for burning off unwanted gas or flammable gas and liquids. The flare includes the foundation, flare tip, structural support, burner, igniter, flare controls including air injection or steam injection systems, flame arrestors, knockout pots, piping and header systems.''

There are three general work practice standards that were proposed for ''fuel gas producing units,'' which may be summarized as follows: (1) The ''no routine flaring'' requirement; (2) flare minimization plan for start-up, shutdown, and malfunction events; and (3) a root-cause analysis for SO_2 releases exceeding 500 lb/day (which was proposed for all affected fuel gas producing units). The ''no routine flaring'' work practice was not intended to prohibit flaring during SSM events; the provisions were intended to apply only during normal operating conditions. We agree with the commenter that suggested that nothing in this rule should be construed to compromise refinery operations and practices with regard to safety. Additionally, as discussed in the preamble to the proposed rule, we specifically rejected a prohibition on flaring for planned start-up and shutdown events. We agree with the commenters that noted that numerous refineries have demonstrated that flare minimization during planned start-up and shutdown activities can greatly reduce flaring during these events. We do believe, however, that a complete elimination of flaring during these events is very site-specific and although it is reported to have been achieved at a limited number of refineries, we do not have information to suggest that it has been adequately demonstrated for universal application. As ''no routine flaring'' is difficult to define in practice, we have re-evaluated BDT using more specific options.

Option 1 is no additional standards for flares. In Option 2, any routine emissions event or any process start-up, shutdown, upset or malfunction that causes a discharge into the atmosphere more than 500 pounds per day of SO_2 (in excess of the allowable emission limit) from an affected fuel gas combustion device or sulfur recovery plant would require a root cause analysis to be performed. This approach is similar to what is included in most consent decrees. We are also including a requirement for continuous monitoring of TRS for all gases flared (including those from upsets, startups, shutdowns, and malfunction events), in order to accurately measure SO_2 emissions from affected flares.

Option 3 includes: (1) The SO_2 root cause analysis in Option 2; (2) a limit on the fuel gas flow rate to the flare of 250,000 scfd; and (3) a flare management plan for SSM events. The flow limit of 250,000 scfd is based on our cost analysis that indicates that for typical gas streams in quantities above this limit, the value of recovered fuel completely offsets the costs of installing and operating recovery systems. Many refineries have implemented flare gas recovery to reduce energy needs and save money. The flare management plan must: (1) Include a diagram illustrating all connections to each affected flare; (2) identify the flow rate monitoring device and a detailed description of manufacturer's specifications regarding quality assurance procedures; (3) include standard operating procedures for planned start-ups and shutdowns of refinery process units that vent to the flare (such as staging of process shutdowns) to minimize flaring during these events; (4) include procedures for a root cause analysis of any process upset or equipment malfunction that causes a discharge to the flare in excess of 500,000 scfd; and (5) include an evaluation of potential causes of fuel gas imbalances (*i.e.*, excess fuel gas), upsets or malfunctions and procedures to minimize their occurrence and records to be maintained to document periods of excess fuel gas. Excess emission events for the flow rate limit of 250,000 scfd and the result of root cause analysis must be reported in the semi-annual compliance reports.

Option 4 is identical to Option 3 except that flaring is limited to 50,000 scfd. This level is estimated to be a baseline level that accounts for the flow requirement needed to maintain safe operations of the flare (*i.e.*, flow of sweep gas and compressor cycle gas). For both Option 3 and Option 4, the limit on the flow rate does not apply during malfunctions and unplanned startups and shutdowns. The flow rate limits in Options 3 and 4 were developed to reduce VOC, SO_2, and NO_X emissions; the limits are based on 30-day rolling average flow rate values.

It is anticipated that a flare gas recovery system will be used to comply with Options 3 and 4 when a flare is currently used on a continuous basis, and the recovered flare gas offsets natural gas purchases. The cost-effectiveness of the flare gas recovery system is primarily dependent on the quantity of gas that the system can recover. Many refineries have already implemented similar work practices through consent decrees and local rules (BAAQMD and SCAQMD), and these requirements have had a demonstrated reduction in flaring events. Flare gas recovery will reduce SO_2, NO_X, and VOC emissions. However, if a refinery produces more fuel gas than the refinery needs to power its equipment, there is no place the refinery can use the recovered fuel gas and there is no additional natural gas purchases to offset. In these cases, flare gas recovery is not considered technically feasible because the excess fuel gas will have to be flared. Therefore, we have included specific provision within the flare management plan to address instances of excess fuel gas. For periods when the refinery owner or operator can demonstrate, through records of natural gas purchases or other means as described in their flare management plan, that the refinery is fuel gas rich, compliance with the flow limit is demonstrated by implementing the procedures described in the flare management plan.

Impacts for each of the four options are based on estimates of current flaring quantities and include the root cause analysis, flare management plan, and flare gas recovery systems when needed. The impacts for each option for new flares are presented in Table 15 to this preamble; impacts for modified and reconstructed flares are presented in Table 16 to this preamble.

TABLE 15.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR WORK PRACTICES CONSIDERED FOR NEW FLARING DEVICES SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons SO_2/yr)	Emission reduction (tons NO_X/yr)	Emission reduction (tons VOC/yr)	Cost-effectiveness ($/ton)	
						Overall	Incremental
2	0	23	15	0	0	1,600	1,600
3	8,800	(1,300)	16	1	41	(23,000)	(31,000)
4	15,000	(840)	16	1	52	(12,000)	43,000

TABLE 16.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR WORK PRACTICES CONSIDERED FOR MODIFIED AND RECONSTRUCTED FLARING DEVICES SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons SO_2/yr)	Emission reduction (tons NO_X/yr)	Emission reduction (tons VOC/yr)	Cost-effectiveness ($/ton)	
						Overall	Incremental
2	0	92	59	0	0	1,600	1,600
3	35,000	(5,300)	64	4	165	(23,000)	(31,000)
4	59,000	(3,300)	66	6	207	(12,000)	43,000

Based on these impacts and consideration of technically feasible operating practices, we conclude that BDT is Option 3. Option 3 includes a set of work practice standards that requires root cause analysis for a discharge into the atmosphere in excess of 500 pounds per day of SO_2 (over the allowable emission limit) from a fuel gas combustion device or sulfur recovery plant or in excess of 500,000 scfd flow to a flare. It also includes a flare

management plan. Finally, fuel gas flow to the flare is limited to 250,000 scfd. To support implementation of these requirements, monitoring and reporting of the flow rate and sulfur content is required. For new flaring devices, this option achieves SO_2 emission reductions of 16 tons/yr from a baseline of 32 tons/yr, NO_X emission reductions of 1 tons/yr from a baseline of 2 tons/yr, and VOC emission reductions of 41 tons/yr from a baseline of 67 tons/yr with a net fuel savings of $23,000 per ton of combined SO_2, NO_X, and VOC. For modified and reconstructed flaring devices, this option achieves SO_2 emission reductions of 64 tons/yr from a baseline of 129 tons/yr, NO_X emission reductions of 4 tons/yr from a baseline of 7 tons/yr, and VOC emission reductions of 165 tons/yr from a baseline of 266 tons/yr with a net fuel savings of $23,000 per ton of combined SO_2, NO_X, and VOC.

The flare gas minimization requirements included in the final standards are important to reduce criteria pollutant emissions and conserve energy. However, we recognize that owners and operators also need to be able to make quick changes to existing process units or flare systems to avoid unsafe conditions. It could take an owner or operator more time to implement the flare requirements, especially flow monitoring and any physical changes needed to comply with the limit on flow to the flare, than it took to implement the change to the flare that caused it to be an affected facility. There is the potential for serious safety concerns if the owner or operator must wait until compliance has been achieved with all of the flare gas minimization requirements prior to venting explosive vapors to the flare or modifying the flare system, such as adding a knockout pot for safety reasons. Moreover, avoiding unsafe conditions by requiring immediate shutdown of all process units connected to the potentially affected flare while the owner or operator takes steps to comply with the final provisions specific to flare gas minimization results in additional emissions, significant costs, and large lost production of refined products. By providing 1 year for modified flares to comply with these flare gas minimization provisions, refinery owners and operators have sufficient time to coordinate the installation of the flow rate and sulfur content monitors, to take whatever steps necessary to meet the flow limitations, to develop and implement the flare management plan, and to make other modifications, if needed, regarding safety and maintenance considerations for other process equipment tied to the flare.

Considering the cost and the energy penalty from the reduction in refined products (*e.g.*, the need to shut down the refinery until the flare gas minimization requirements can be met) and emissions associated with the immediate application of these requirements of the rule to modified flares, we determined that BDT was to phase in the requirements. The owner or operator of a modified flare would have to comply with the applicable H_2S limit immediately and would have 1 year to implement the flare gas minimization requirements. Therefore, the final standards specify that for modified flares, the H_2S limits for fuel gas combustion units apply immediately and the flare gas minimization requirements apply no later than 1 year after the flare becomes an affected facility. For newly constructed and reconstructed flares, the H_2S limits and all of the flare gas minimization requirements apply immediately upon start-up of the affected flare.

Comment: Several commenters requested clarification of how one would assess a flare ''modification.'' Questions included: (1) How the emission basis of a flare should be calculated; (2) if the modification determination would be based on flare capacity or increase in discharge capability of units connected to the flare; (3) whether the modification determination would include all possible flaring events or just non-emergency flaring; (4) whether adding a new line to a flare is considered to increase the capacity of the flare and cause a modification; (5) whether flare tip replacements are considered routine maintenance instead of a modification of the flare, even if the new flare tip has a different geometry (*e.g.*, a larger diameter to reduce noise); and (6) how SSM streams are considered when calculating baseline emissions for a modification determination. The commenters also suggested that EPA should clarify whether and how the exemption in § 60.14(e)(2) applies to a flare, including how the production rate for a flare would be defined.

Response: Section 60.14(a) defines modification as follows: ''Except as provided in paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification.'' Section 60.14(e) provides exclusions for maintenance activities, increased production rates, increased hours of operation, etc. However, except for the maintenance exclusion, the other exemptions are either not applicable or ambiguous when applied to a flare. More importantly, § 60.14(f) states that ''Applicable provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.'' Therefore, to eliminate ambiguity, we specifically define what constitutes a flare modification in subpart Ja.

A flare is considered to be modified in one of two ways. First, a flare is considered to be modified when any piping from a refinery process unit or fuel gas system is newly connected to the flare. This new piping could allow additional gas to be sent to the flare, consequently increasing emissions from the flare. Second, a flare is considered to be modified if that flare is physically altered to increase flow capacity.

While in most cases an affected facility must comply with the final standard if it commences construction, reconstruction or modification after the proposal date, section 111(a)(2) of the CAA also provides that in certain circumstances such a source only need comply with the standard if it commences construction after the final date. Given the number of changes between proposal and final, we have concluded that this is one of the rare cases in which the final, rather than proposal, date applies.

In this case, we are promulgating a newly defined affected facility, adding a new provision specifically defining what constitutes a modification of a flare, adding several new requirements, and adding a definition of a flare. All of these changes significantly alter what would be an affected facility and the obligations of the affected facility for purposes of reducing flaring. Furthermore, while some of the requirements that were proposed for the fuel gas producing unit were transferred to the flare as an affected source, the scope of these requirements changed significantly when they were applied to a flare rather than a fuel gas producing unit. Specifically, under the proposal, only the gas stream from the modified fuel gas producing unit was barred from routine flaring. Under the final rule, however all of the units connected to the flare are now addressed, not just the fuel gas producing unit that was new, modified, or reconstructed.

Accordingly, we are providing in the final standards that only those flares commencing construction, reconstruction, or modification after June 24, 2008 must meet the requirements in subpart Ja. Flares

commencing construction, reconstruction, or modification after June 11, 1973, and on or before June 24, 2008 must meet the requirements in subpart J regarding fuel gas combustion devices (*i.e.*, the H_2S fuel gas limit).

J. Delayed Coking Units

Comment: Several commenters supported the proposal that requires delayed coking units to depressure the coke drums to the fuel gas system down to 5 psig. One commenter supported venting the delayed coker gas to a flare or to the atmosphere at pressures less than 5 psig; at pressures greater than 5 psig, the commenter suggested that the rule should only prohibit gases from being sent to a flare and allow any other disposition. That is, the commenter stated that EPA should not restrict the disposition of the coker depressurization gas to only the fuel gas system.

One commenter supported inclusion of a coke drum pressure limit above which the coke drum exhaust gases must be sent to a recovery system, disagreed that it is technically infeasible to divert emissions for recovery at pressures below 5 psig, and urged EPA to require venting until the pressure drops below 2 psig. The commenter recently issued a permit including the 2 psig level, and although the modification has not been completed, the commenter believes the requirement is technically feasible.

A number of commenters objected to the finding that BDT is to depressure delayed coking units to the fuel gas system down to 5 psig. Commenters provided examples of coking units whose current mode of operations (*e.g.*, set points or timed cycles) may divert to a flare or to the atmosphere at pressures of approximately 10 to 20 psig and that it would not be cost-effective to modify these units to comply with the proposed work practice standard. One commenter supported the premise that it is cost-effective for delayed coking discharge to be routed to fuel gas blowdown, but depressurization down to 5 psig may not be feasible with existing equipment; the commenter recommended that the work practice simply require a closed blow down system following procedures described in the facility's SSM plan. At a minimum, an alternative is needed for existing units that would require capital expenditure to meet the 5 psig proposal. One commenter stated that compressors cannot recover blowdown system gases at pressures below the fuel gas recovery compressor suction pressure. The minimum pressure at which a suction compressor can operate depends on the design of the coking unit and the blowdown management system. Because there is uncertainty surrounding the available emission information, the costs are not minimal in most cases, and the emissions are difficult to measure, the commenter stated that EPA cannot determine that controls on coker vents is BDT.

Response: Based on the public comments, we re-evaluated BDT for delayed coking units. We considered three options: (1) Depressurization down to 15 psig; (2) depressurization down to 5 psig; and (3) depressurization down to 2 psig. We estimated that the baseline is, on average, depressurization down to 15 psig and then venting to the atmosphere. Therefore, there are no impacts for Option 1. Impacts for Options 2 and 3 were estimated based on the baseline conditions, the size of typical coke drums, and cost information provided in public comments. We also collected emissions test data to support and verify the projected emissions and emission reductions. The impacts for each option for new delayed coking units are presented in Table 17 to this preamble; impacts for modified and reconstructed delayed coking units are presented in Table 18 to this preamble.

TABLE 17.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR WORK PRACTICES CONSIDERED FOR NEW DELAYED COKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons SO_2/yr)	Emission reduction (tons VOC/yr)	Cost-effectiveness ($/ton)	
					Overall	Incremental
2	2,400	230	170	2	1,300	1,300
3	24,000	2,300	230	3	9,900	38,000

TABLE 18.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR WORK PRACTICES CONSIDERED FOR MODIFIED AND RECONSTRUCTED DELAYED COKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons SO_2/yr)	Emission reduction (tons VOC/yr)	Cost-effectiveness ($/ton)	
					Overall	Incremental
2	14,000	1,400	260	4	5,100	5,100
3	54,000	5,100	340	5	15,000	47,000

Based on these impacts and consideration of technically feasible operating practices, we confirmed our conclusion at proposal that BDT is depressurization down to 5 psig, or Option 2. For new delayed coking units, this option achieves SO_2 emission reductions of 170 tons/yr from a baseline of 520 tons/yr and VOC emission reductions of 2 tons/yr from a baseline of 7 tons/yr at a cost of $1,300 per ton of combined SO_2 and VOC. For modified and reconstructed delayed coking units, this option achieves SO_2 emission reductions of 260 tons/yr from a baseline of 780 tons/yr and VOC emission reductions of 4 tons/yr from a baseline of 11 tons/yr at a cost of $5,100 per ton of combined SO_2 and VOC. Although Option 3 has been established in one refiner's permit, this level of depressurization has not been demonstrated in practice. Additionally, the difference in the quantity of gas released when the set point is 2 psig rather than 5 psig is relatively small, 80 tons of SO_2 and 4 tons of VOC, and the resulting incremental cost-effectiveness from Option 2 to Option 3 is about $40,000/ton, which is much greater. Therefore, Option 3, or depressurization down to 2 psig, is not BDT.

K. Other Comments

Comment: One commenter contested the criteria EPA used in its Regulatory Flexibility Act/Small Business Regulatory Enforcement Fairness Act (RFA/SBREFA) analysis for defining a

small refiner as one with no more than 1,500 employees or more than 125,000 barrels per day (BPD) average crude capacity and requested that EPA use what the commenter alleged is the commonly recognized definition in other EPA programs of no more than 1,500 employees or more than 155,000 BPD average crude capacity. The commenter noted that EPA did not make any effort in the Regulatory Impact Analysis or in the proposal preamble to support its selection or explain why it adopted this definition.

Response: Under the SBA regulations, a small refiner is defined as a refinery with no more than 1,500 employees. See Table in 13 CFR 121.201, NAICS code 324110. Additionally, for government procurement purposes only, footnote 4 to that Table further provides that a small refinery must meet a certain capacity threshold as follows: ''For purposes of Government procurement, the petroleum refiner must be a concern that has no more than 1,500 employees nor more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity.'' After reviewing our analysis, we realized that we inadvertently used the capacity limit to evaluate the impacts on small refiners; the definition that should have been used is 1,500 employees with no capacity limit. We have recalculated the economic impact on the small entities using the corrected definition of small refiner, and our conclusion that the rule will not have a significant economic impact on a substantial number of small entities has not changed. See section VI.C of this preamble and the Regulatory Impacts Analysis (RIA) in the docket for additional details.

The commenter is incorrect in asserting that EPA uses any other definition for small refiner than the SBA definition when conducting its RFA/SBREFA analysis in other rulemakings. EPA consistently uses the SBA definition of a small refiner for such purposes. However, in promulgating regulations, EPA may define a small refiner differently when deciding what standards and requirements apply to these facilities. For example, in the fuel standards promulgated by EPA (*e.g.*, Control of Air Pollution From New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (65 FR 6698)), EPA set different requirements for small refiners than for all other refiners, and the 155,000 BPD capacity cutoff cited by the commenter is one of the criteria used to define a small refiner in those standards. See 40 CFR 80.225. However, the RFA/SBREFA analysis conducted in that rulemaking regarding whether those rules had a significant economic impact on a substantial number of small entities was not conducted based on any capacity cutoff. See 65 FR 6817.

Comment: One commenter stated that EPA is required under section 111 of the CAA to promulgate NSPS for each of the pollutants emitted by the source category that cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The commenter stated that there is scientific consensus that greenhouse gases are a leading cause of global warming, and anthropogenic emissions of greenhouse gases (GHG) such as CO_2 and methane (CH_4) are increasing and driving the warming. Petroleum refineries are a significant source of fossil fuel CO_2 emissions because they consume large quantities of energy, and in fact, U.S. petroleum refineries consume over 3.2 percent of the total U.S. energy consumption. Petroleum refineries also emit CH_4 and are responsible for an additional 0.6 teragrams of CO_2 equivalence via CH_4 emissions. Therefore, the commenter believes that EPA must set NSPS for CO_2 and CH_4 because petroleum refineries' emissions of CO_2 and CH_4 cause and contribute significantly to air pollution which may reasonably be anticipated to endanger public health and welfare.

Two commenters cited the Supreme Court decision in *Massachusetts* v. *EPA*, where the Court found that carbon dioxide and other GHG fit into the statutory definition of ''air pollutant'' in the CAA. Commenter 0128 stated that in *Massachusetts* v. *EPA*, the Supreme Court rejected EPA's overly narrow interpretation that greenhouse gases do not fall under the definition. The Court also voided EPA's term ''air pollution'' and noted that because greenhouse gases both enter the ambient air and warm the atmosphere, they are unquestionably agents of air pollution.

Another commenter contended that while the decision in *Massachusetts* v. *EPA* states that GHG are ''air pollutants'' as that term is used in CAA section 111, section 111 does not require EPA to address all air pollutants in NSPS. Therefore, the Supreme Court's decision does not mean that EPA necessarily must regulate GHG through NSPS. Instead of beginning to address GHG in specific NSPS, the commenter stated that EPA should develop a comprehensive plan for addressing GHG that ensures that ''any necessary reductions in GHG emissions are achieved in a consistent and equitable manner across all industry sectors.'' The commenter further stated that since the issue of GHG emissions was not raised in the proposal preamble for subparts J and Ja, it would be inappropriate for EPA to promulgate GHG standards in those subparts without first proposing the new standards.

Response: While section 111(b)(1)(B) of the CAA permits EPA, under appropriate circumstances, to add new standards of performance for additional pollutants concurrent with the 8-year review of existing standards, for the reasons set forth below, EPA declines to promulgate performance standards for GHG, including CO_2 and CH_4, from petroleum refineries as part of this 8-year review cycle.

Section 111(b)(1)(B) imposes two obligations upon EPA for a source category listed under section 111(b)(1)(A). First, within 1 year of listing a source category, section 111(b)(1)(B) requires the Administrator to ''publish proposed regulations, establishing Federal standards of performance for new sources'' within such category. After providing ''interested persons an opportunity for written comment on such proposed regulations,'' EPA must then ''promulgate, within one year after such publication, such standards'' as the Administrator ''deems appropriate.'' The Agency has always interpreted this initial requirement as providing the Administrator with significant flexibility in determining which pollutants are appropriate for regulation under section 111(b)(1)(B). See *National Lime Assoc.* v. *EPA*, 627 F.2d 416, 426 (DC Cir. 1980) (explaining reasons for not promulgating standards for NO_X, SO_2, and CO from lime plants); see also *National Assoc. of Clean Air Agencies* v. *EPA*, 489 F.3d 1221, 1228–1230 (DC Cir. 2007) (finding that the ''deems appropriate'' language in CAA section 231 provides a ''delegation of authority'' that is ''both explicit and extraordinarily broad,'' giving EPA's regulation ''controlling weight unless it is manifestly contrary to the statute'').

Second, the statute requires that:

> ''The Administrator shall, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards. Notwithstanding the requirements of the previous sentence, the Administrator need not review any such standard if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such standard.''

Nothing in the 8-year review provision mandates that EPA include a new standard of performance for an air pollutant not already covered by the

standard of performance under review. Instead, the 8-year review provision can be reasonably understood as requiring ''review'' of only ''such standards'' [1] as were previously promulgated. As there would be no standard to review for an air pollutant not already subject to the standard, there would be no requirement for promulgating a new standard of performance since the ''review'' requirement in section 111(b)(1)(B) cannot be transformed into a ''promulgation'' requirement.[2] Moreover, as noted above, even if the 8-year review provision were a ''promulgation'' requirement, such a requirement still would not mandate that EPA set performance standards for all air pollutants emitted from the source category. In the 1990 CAA Amendments, Congress amended the definition of ''standard of performance'' to be ''a standard for emissions of air pollutants,'' specifically deleting the word ''any'' from the phrase ''any air pollutant'' that was contained in the 1977 definition. This amendment restored the definition to the 1970 version. This deliberate change demonstrates that Congress was aware that the 1970 definition did not require EPA to cover all air pollutants emitted from a source category. Additionally, by reinstating the 1970 definition through the 1990 CAA amendments, Congress was also indicating its understanding that EPA is not required to regulate all air pollutants emitted from a source under section 111.

EPA has promulgated new performance standards for pollutants not previously covered concurrent with some previous 8-year review rulemakings. See 52 FR 24672, 24710 (July 1, 1987) (considering PM_{10} controls in future rulemakings); 71 FR 9866 (February 27, 2006) (new PM standards for boilers). Additionally, as commenters correctly point out, EPA is promulgating a new standard of performance for NO_X emissions from certain affected facilities at refineries in this rulemaking. However, contrary to commenters' assertions,[3] these actions were discretionary; EPA may, but is not required to, promulgate new standards of performance concurrent with its 8-year review. While it may often be appropriate for EPA to exercise its discretion by promulgating new standards of performance concurrent with an 8-year review, because it is in the process of gathering information and reviewing controls for an industry, for the reasons set forth above, EPA reasonably interprets section 111(b)(1)(B) to not mandate such a result.

In this instance, it is reasonable for EPA not to promulgate performance standards for GHG emissions as part of this 8-year review cycle. We believe that the nature of GHG emissions renders them readily distinguishable from other air pollutants for which we have previously promulgated new performance standards concurrent with an 8-year review of the existing standards. Indeed, GHG emissions present issues that we have never had to address in the context of even an initial NSPS rulemaking for a source category. These differences warrant proceeding initially through a more deliberate process, *i.e.*, the announced advanced notice of proposed rulemaking (ANPR), than in this source category-specific rulemaking. While commenters correctly note that we have previously exercised our discretion to promulgate new performance standards concurrent with an 8-year review, and indeed are doing so here with respect to NO_X, the exercise of that discretion had limited impact as those air pollutants were either already regulated elsewhere under the Act or were emitted by a sufficiently limited subset of source categories. Here, promulgating new performance standards for these air pollutants in this one source category could potentially mandate regulation for numerous other source categories under several other parts of the Act. Similarly, our initial decision to regulate non-National Ambient Air Quality Standards (NAAQS) air pollutants in an NSPS has generally raised issues limited to the source category before us. For example, with the exception of landfill related air pollutants,[4] our decisions to regulate non-NAAQS air pollutants were reached at a time prior to the enactment of the statutory Prevention of Significant Deterioration (PSD) program and accordingly did not implicate the many complexities that we are struggling with today and which we intend to address in the ANPR discussed below. *See* 45 FR 52,676, 52,708–10 (Aug. 7, 1980).

In contrast to those circumstances, the regulation of GHG emissions raises numerous issues that are not well suited to initial resolution in a rulemaking directed at an individual source category. To that end, as Administrator Johnson announced on March 27, 2008, in letters to Senator Barbara Boxer and Representative John Dingell, it is his intent to issue an ANPR in the very near future that explores and seeks public comment on the many complex interconnections between the relevant sections of the Clean Air Act, including section 111, and lays the foundation for a comprehensive path forward with respect to regulation of all GHG.

We have previously noted that at this stage it is most appropriate to address these complexities in an ANPR addressing a variety of interconnected statutory provisions. In his April 10, 2008, testimony before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce, U.S. House of Representatives, Robert J. Meyers, Principal Deputy Assistant Administrator of the Office of Air and Radiation, further elaborated on the reasons for and anticipated content of an ANPR and discussed some of these complexities. For example, he noted the potential complexities resulting from implementation of the PSD preconstruction review permitting program:

> For PSD purposes, major stationary sources are those with the potential to emit 100 tons per year of a regulated air pollutant in the case of certain statutorily-listed source categories, and 250 tons per year in the case of all other source categories. New large schools, nursing homes, and hospitals could be considered a ''major source'' under this section of the Clean Air Act. For modifications, only those that increase

[1] Commenters assert that ''the term 'such standards' incorporates the inclusive 'any' air pollutant language in the definition of a 'standard of performance' '' and therefore contemplates new standards of performance during the 8-year review. See Comments, pg. 3. However, the word ''any'' does not appear in the definition of ''standard of performance'' in the manner quoted by commenters. See CAA section 111(a)(1).

[2] Commenters assert that EPA must develop performance standards during the 8-year review ''for *any* air pollutant'' emitted by a source ''provided that EPA finds those emissions cause or contribute to air pollution'' that may endanger public health or welfare. See Comments, pg. 2. To the extent any such finding were required, EPA notes that no such finding has been made regarding GHG emitted from refineries. Indeed, 111(b)(1)(A), which contains the only endangerment finding requirement in section 111, gives the Administrator significant discretion on the timing of endangerment findings after the initial set of source category listings (''from time to time thereafter shall revise''). Nothing in the statute ties the endangerment and 8-year review requirements. Hence, commenters' own arguments lack merit and EPA is under no obligation for promulgating GHG performance standards for refineries.

[3] Commenters again predicate their assertions on a prerequisite endangerment finding. See Comments, pg. 4. As explained in footnote 2, EPA has made no such finding and therefore under petitioners' interpretation is under no obligation to promulgate GHG performance standards for this source category.

[4] Because of the unique nature of landfill related air pollutants the Agency determined it was appropriate to define the air pollutants at issue as emissions from landfills and thus limited the potential implications for other programs. *See* 56 FR 24468, 24470 (May 30, 1991). In other words, only landfills emit these particular air pollutants; thus, it was appropriate that only this source category was subject to the PSD program for this air pollutant.

emissions above a tonnage threshold established by EPA for each regulated pollutant through rulemaking triggers PSD. Until EPA establishes this so-called ''significance'' level, however, any increase in a regulated pollutant at a major stationary source undergoing a modification would trigger PSD permitting.

As noted previously, PSD sources are required to install best available control technology (BACT). BACT must be at least as stringent as any applicable NSPS, and is to reflect the maximum degree of emissions reduction achievable for such a facility, taking into account energy, environment and economic impacts and other costs.

Controlling GHG emissions under any section of the Clean Air Act could significantly increase the number of stationary sources subject to PSD permitting.

Because CO_2 is typically emitted in larger quantities than criteria and other traditional air pollutants from combustion sources, facilities not previously subject to Clean Air Act permitting—such as large commercial and residential buildings heated by natural gas boilers—could qualify as major stationary sources for PSD purposes. In addition, some small industrial sources not now covered by PSD could be expected to become subject to PSD due to their GHG emissions.

Currently, our best estimate of the potential impact of including GHG in the PSD program is that the number of PSD permits issued annually nationwide could rise by an order of magnitude above the current 200–300 a year. Such estimates are subject to significant uncertainty. At present, we do not have comprehensive information on GHG emissions from the many categories of stationary sources of such emissions; instead we have relied on available information and general engineering estimates.

Such a broadening of the PSD program could pose significant implementation issues for covered facilities (particularly newly covered facilities) and permitting agencies. EPA is examining the scope of these potential difficulties and whether, for GHG, the program could be limited to larger sources, at least temporarily, in view of the very substantial increase in administrative burden that might otherwise occur. However, at present it is unclear as to whether EPA has the legal discretion to exempt sources above the statutory thresholds. In addition, EPA is exploring concepts for streamlining implementation of the PSD program for smaller sources, such as guidance on general permits or source definitions for BACT determinations and model permits for use by permitting agencies. EPA will address permitting issues in greater detail in the planned ANPR.

Given the complexity of PSD issues arising from regulation of GHG emissions, among other complex issues of regulating a pollutant—particularly a pollutant global in nature—for the first time under the CAA, it is reasonable for the Agency to proceed first by evaluating these issues, and other potential complexities, in the previously announced ANPR rather than by taking action to promulgate performance standards for GHG emissions in this rulemaking.

In addition to the reasons set forth above, it is appropriate for EPA to decline to promulgate performance standards for GHG emissions concurrent with this 8-year review as section 111(b)(1)(B) does not require that the Agency revise the standards when essential information becomes available too late in the review period. The 8-year review provision itself conditions the need to review a standard on ''readily available information on the efficacy of such standard.'' CAA section 111(b)(1)(B). The legislative history of the 1970 CAA predecessor for the review provision also states that the review obligation depends on the availability of ''new technology processes or operating methods.'' 1970 Sen. Comm. Rep. at 17. Additionally, the *Massachusetts* decision, which held that GHG are air pollutants, was handed down merely four weeks before the court-ordered deadline to propose the standards for this 8-year review period. As explained above, section 111(b)(1)(B) contemplates a two-year period for NSPS promulgation, and, as noted below, the consent decree under which EPA was acting contemplated a two-and-a-half year period for this 8-year review; hence, EPA did not have sufficient time within this rulemaking for proposing and promulgating performance standards for GHG emissions from refineries. The following discussion provides more information regarding the timeline of events for this particular rulemaking's review period.

EPA entered into a consent decree with the Sierra Club and Our Children's Earth Foundation on October 31, 2005, that required EPA to conduct its review of 40 CFR part 60, subpart J and propose revisions by April 30, 2007, and to promulgate a final rule by April 30, 2008. EPA began its review of subpart J and drafted a proposal package. Shortly before EPA sent the proposed rule package to OMB for its review, the U.S. Supreme Court, on April 2, 2007, issued its decision in *Massachusetts* v. *EPA*, holding that GHG are air pollutants under the CAA, and remanding the case for the Agency to take action consistent with the Court's opinion. Less than one month later, EPA was obligated under the terms of its consent decree to propose revisions to subpart J by April 30, 2007; this proposed rule did not include performance standards for GHG emissions. On August 27, 2007, EPA received comments from Earthjustice asserting that EPA, as part of its 8-year review under section 111(b)(1)(B), must promulgate GHG emissions limits for petroleum refineries. On September 14, 2007, the *Massachusetts* case was officially remanded to the Agency by the DC Circuit Court of Appeals. Under the terms of the consent decree, EPA was obligated to finalize its subpart J revisions by April 30, 2008. Considering this timeline of events, and the complexities of the issues involved, EPA would not have had sufficient time during this particular 8-year review of subpart J to propose and promulgate GHG performance standards for refineries even if the Agency had deemed such action appropriate. As explained above, the Agency will use the information it gathers through the ANPR for determining what may be appropriate for future rulemakings.

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

A. What are the impacts for petroleum refinery process units?

We are presenting estimates of the impacts for the final requirements of subpart Ja that change the performance standards for the following: (1) The emission limits for fluid catalytic cracking units, sulfur recovery plants, fluid coking units, fuel gas combustion devices, and process heaters; and (2) the work practice standards for flares and delayed coking units. The final amendments to 40 CFR part 60, subpart J are clarifications to the existing rule and they have no emission reduction impacts. The cost, environmental, and economic impacts presented in this section are expressed as incremental differences between the impacts of petroleum refinery process units complying with the final subpart Ja and the current NSPS requirements of subpart J (*i.e.*, baseline). The impacts are presented for petroleum refinery process units that commence construction, reconstruction, or modification over the next 5 years. The analyses and the documents referenced below can be found in Docket ID No. EPA–HQ–OAR–2007–0011.

In order to determine the incremental costs and emission reductions of this final rule, we first estimated baseline impacts. For new sources, baseline costs and emission reductions were estimated for complying with subpart J; incremental impacts for subpart Ja were estimated as the costs to comply with subpart J subtracted from the costs to comply with final subpart Ja. Sources that are modified or reconstructed over the next 5 years must comply with subpart J in the absence of final subpart Ja. Prior to reconstruction or modification, these sources will either be subject to a consent decree

(equivalent to about 77 percent of the industry by capacity), complying with subpart J or equivalent limits, and/or complying with 40 CFR part 63, subpart UUU (MACT II). Baseline costs and emission reductions were estimated as the effort needed to comply with subpart J from one of those three starting points. The costs and emission reductions to comply with final subpart Ja were estimated from those starting points as well. For further detail on the methodology of these calculations, see Docket ID No. EPA–HQ–OAR–2007–0011.

When considering and selecting emission limits for the final rule, we evaluated the cost-effectiveness of each option for new sources separately from reconstructed and modified sources. In most cases, our selections for each process unit and pollutant were consistent for modified and reconstructed units and new units. In this section, we are presenting our costs and emission reductions for the overall rule. We estimate that the final amendments will reduce emissions of PM by 1,300 tons/yr, SO_2 by 17,000 tons/yr, NO_X by 11,000 tons/yr, and VOC by 200 tons/yr from the baseline. The estimated increase in annual cost, including annualized capital costs, is about $31 million (2006 dollars). The overall cost-effectiveness is about $1,070 per ton of combined pollutants removed. The estimated nationwide 5-year incremental emissions reductions and cost impacts for the final standards are summarized in Table 19 of this preamble.

TABLE 19.—NATIONAL INCREMENTAL EMISSION REDUCTIONS AND COST IMPACTS FOR PETROLEUM REFINERY UNITS SUBJECT TO FINAL STANDARDS UNDER 40 CFR PART 60, SUBPART JA (FIFTH YEAR AFTER PROPOSAL)

Process unit	Total capital cost ($1,000)	Total annual cost ($1,000/yr)	Annual emission reductions (tons PM/yr)	Annual emission reductions (tons SO_2/yr)	Annual emission reductions (tons NO_X/yr)	Annual emission reductions (tons VOC/yr)	Cost effectiveness ($/ton)
FCCU	8,500	6,400	240	4,300	2,600	.....	890
FCU	14,000	4,000	1,000	5,900	660	.....	530
SRP	1,700	730	.....	420	.....	.....	1,700
Fuel gas combustion devices	34,000	12,000	.....	5,200	.....	.....	2,300
Process heaters	23,000	12,000	.....	.....	7,500	.....	1,600
Flaring	40,000	−7,000	.....	80	6	200	−23,000
Delayed coking units	17,000	1,600	.....	440	.....	25	3,400
Sulfur pits	8,300	1,000	.....	300	.....	.....	3,400
Total	150,000	31,100	1,300	17,000	11,000	1,400	1,070

B. What are the secondary impacts?

Indirect or secondary air quality impacts of this final rule will result from the increased electricity usage associated with the operation of control devices. If plants purchase electricity from a power plant, we estimate that the final standards will increase secondary emissions of criteria pollutants, including PM, SO_2, NO_X, and CO from power plants. For new, modified or reconstructed sources, this final rule will increase secondary PM emissions by 56 Megagrams per year (Mg/yr) (62 tons/yr); secondary SO_2 emissions by about 1,400 Mg/yr (1,500 tons/yr); and secondary NO_X emissions by about 530 Mg/yr (580 tons/yr) for the 5 years following proposal.

As explained earlier, we expect that affected facilities will control emissions from fluid catalytic cracking units by installing and operating ESP or wet gas scrubbers. We also expect that the emissions from the affected FCU will be controlled with a wet scrubber. For these process units, we estimated solid waste impacts for both types of control devices and water impacts for wet gas scrubbers. In addition, the controls needed by small sulfur recovery plants will generate condensate. We project that this final rule will generate 1.6 billion gallons of water per year for the 5 years following proposal. We also estimate that this final rule will generate 2,200 Mg/yr (2,400 tons/yr) of solid waste over those 5 years.

Energy impacts as defined in this preamble section consist of the electricity and steam needed to operate control devices and other equipment that would be required under the final rule. Our estimate of the increased energy demand includes the electricity needed to produce the required amounts of steam as well as direct electricity demand. We project that this final rule will increase overall energy demand by about 410 gigawatt-hours per year (1,400 billion British thermal units per year). An analysis of energy impacts that accounts for reactions in affected markets to the costs of this final rule can be found in the section on Executive Order 13211 found later in this preamble.

C. What are the economic impacts?

Our economic impact analysis estimated the impacts on product price and output that the final NSPS would have on five petroleum products—motor gasoline, jet fuel, distillate fuel oil, residual fuel oil, and liquefied petroleum gases. This analysis estimates in the fifth year after proposal that the price of these petroleum products will increase less than 0.01 percent nationally along with a corresponding reduction in output of less than 0.01 percent. The overall total annual social costs, which reflect changes in consumer and producer behavior in response to the compliance costs, are $27 million ($2006) in the fifth year after proposal or almost identical to the compliance costs incurred by affected producers of these petroleum products.

For more information, please refer to the regulatory impact analysis (RIA) that is in the docket for this final rule.

D. What are the benefits?

We estimate the monetized benefits of this final rule to be $220 million to $1.9 billion (2006$) in the fifth year after proposal. We base the benefits estimate derived from the $PM_{2.5}$ and $PM_{2.5}$ precursor emission reductions on the approach and methodology laid out in the Technical Support Document that accompanied the recently completed Regulatory Impact Analysis (RIA) for the revision to the National Ambient Air Quality Standard for Ground-level Ozone (NAAQS), March 2008. We generated estimates that represent the total monetized human health benefits (the sum of premature mortality and premature morbidity) of reducing one ton of $PM_{2.5}$ and $PM_{2.5}$ precursor

emissions. A summary of the range of benefits estimates at discount rates of 3% and 7% is in Table 20 of this preamble.

TABLE 20.—SUMMARY OF THE RANGE OF BENEFITS ESTIMATES FOR FINAL REFINERIES NSPS

Pollutant	Monetized benefits per ton emission reduction (3% discount)	Monetized benefits per ton emission reduction (7% discount)	Emission reductions (tons)	Total monetized benefits (millions of 2006 dollars, 3% discount) [1]	Total monetized benefits (millions of 2006 dollars, 7% discount) [1]
Direct $PM_{2.5}$	$68,000 to $570,000.	$63,000 to $520,000.	1,054	$72 to $600	$66 to $540.
$PM_{2.5}$ Precursor:					
SO_2	$8,000 to $68,000	$7,400 to $62,000	16,714	$130 to $1,100	$120 to $1,000.
NO_X	$1,300 to $11,000	$1,200 to $9,600	10,786	$14 to $110	$13 to $100.
VOC	$210 to $1,700	$190 to $1,500	230	$0.05 to $.38	$0.04 to $.35.
			Grand total	$220 to $1,900	$200 to $1,700.

[1] All estimates are for the analysis year (fifth year after proposal, 2012), and are rounded to two significant figures so numbers may not sum across columns. Emission reductions reflect the combination of selected options for both new and reconstructed/modified sources. The $PM_{2.5}$ fraction of total PM emissions is estimated at 83.3%, and only the reduction in the $PM_{2.5}$ fraction is monetized in this analysis. All fine particles are assumed to have equivalent health effects, but the benefit per ton estimates vary because each ton of precursor reduced has a different propensity to become $PM_{2.5}$. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles.

The specific estimates of benefits per ton of pollutant reductions included in this analysis are largely driven by the concentration response function for premature mortality, which is based on the PM Expert Elicitation study (Industrial Economics, Inc., September 2006. *Expanded Expert Judgment Assessment of the Concentration-Response Relationship Between $PM_{2.5}$ Exposure and Mortality*. Prepared for the U.S. EPA, Office of Air Quality Planning and Standards). The preamble for the proposal indicated that EPA would update the benefits estimates to incorporate the results of the expert elicitation for the final rule, and we have done so. The range of benefits estimates presented above represents the range from the lowest expert estimate to the highest expert estimate to characterize the uncertainty in the concentration response function. To generate the benefit-per-ton estimates, we used a model to convert emissions of direct $PM_{2.5}$ and $PM_{2.5}$ precursors into changes in $PM_{2.5}$ air quality and another model to estimate the changes in human health based on that change in air quality. Finally, the monetized health benefits were divided by the emission reductions to create the benefit-per-ton estimates. Even though all fine particles are assumed to have equivalent health effects, the benefit-per-ton estimates vary because each ton of precursor reduced has a different propensity to become $PM_{2.5}$. For example, NO_X 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.

This analysis does not include the type of detailed uncertainty assessment found in the PM NAAQS RIA because we lack the necessary air quality input and monitoring data to run the benefits model. However, the 2006 PM NAAQS analysis provides an indication of the sensitivity of our results to the use of alternative concentration response functions, including those derived from the PM expert elicitation study.

The annualized costs of this rulemaking are estimated at $31 million (2006 dollars) in the fifth year after proposal, and the benefits are estimated at $220 million to $1.9 billion (2006 dollars) for that same year. Thus, net benefits of this rulemaking are estimated at $190 million to $1.8 billion (2006 dollars). EPA believes that the benefits are likely to exceed the costs by a significant margin even when taking into account the uncertainties in the cost and benefit estimates. It should be noted that the range of benefits estimates provided above does not include ozone-related benefits from the reductions in VOC and NO_X emissions expected to occur as a result of this final rule, nor does this range include benefits from the portion of total PM emissions reduction that is not $PM_{2.5}$. We do not have sufficient information or modeling available to provide such estimates for this rulemaking. For more information, please refer to the RIA for this final rule that is available in the docket.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and 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, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the RIA for the Final Petroleum Refinery NSPS. A copy of the analysis is available in the docket for this action and the analysis is briefly summarized here. The monetized benefits of this action are estimated as a range from $220 million to $1.9 billion (2006 dollars), and the annualized costs of this action are $31.1 million (2006 dollars). We also estimated the economic impacts, small business impacts, and energy impacts associated with this action. These analyses are included in the RIA and are summarized elsewhere in this preamble.

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 add a monitoring exemption for fuel gas streams combusted in a fuel gas combustion device that are inherently low in sulfur content. The exemption applies to fuel gas streams that meet specified criteria or that the owner or operator demonstrates are low sulfur according to the rule requirements. The owner or operator is required to submit a written application for the exemption containing information needed to document the low sulfur content. The application is not a mandatory requirement and the incremental reduction in monitoring burden that

will occur as a result of the exemption is not significant compared to the baseline burden estimates for the existing rule. Therefore, we have not revised the information collection request (ICR) for the existing rule. However, OMB has previously approved the information collection requirements 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, EPA ICR number 1054.09. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9.

The information collection requirements in the final standards of performance for petroleum refineries (40 CFR part 60, subpart Ja) have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.* The information collection requirements are not enforceable until OMB approves them.

The information collection requirements in this final rule are needed by the Agency to determine compliance with the standards. These requirements are based on recordkeeping and reporting requirements in the NSPS General Provisions in 40 CFR part 60, subpart A, and on specific requirements in subpart J or subpart Ja which are mandatory for all operators subject to new source performance standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to EPA policies set forth in 40 CFR part 2, subpart B.

The final standards of performance for petroleum refineries include work practice requirements for delayed coking reactor vessel depressuring and written plans to minimize emissions from flares. Plants also are required to analyze the cause of any exceedance that releases more than 500 pounds per day of SO_2 from an affected fuel gas combustion device. The final standards also include testing, monitoring, recordkeeping, and reporting provisions. Monitoring requirements include control device operating parameters, bag leak detection systems, or CEMS, depending on the type of process, pollutant, and control device. Exemptions are also included for small emitters.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 5,340 labor-hours per year at a cost of $481,249 per year. The annualized capital costs are estimated at $2,052,000 per year and operation and maintenance costs are estimated at $1,117,440 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 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 EPA's regulations are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) 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 will 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, depending on the size definition for the affected NAICS code (as defined by Small Business Administration (SBA) 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.

After considering the economic impact of this final rule 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 the current standards of performance for petroleum refineries are small refineries. After reviewing the small business analysis for the proposed NSPS, we realized that we inadvertently used the capacity limit of 125,000 barrels/day production as part of the small business size standard to evaluate the impacts on small refiners; the definition that should have been used is 1,500 employees for an ultimate parent entity with no capacity limit in the United States. The effect of this change in the small business size standard for this analysis is one additional small refiner. This change in the small business size standard does not lead to any effect on the certification that there is no significant economic impact on a substantial number of small entities resulting from today's action. We have determined that, of the 58 entities that are in the affected industry, 25 of these (or 43 percent) are classified as small according to the SBA small business size standard listed previously. Of these 25 affected entities, three are expected to be affected by today's action. None of these three small entities is expected to incur an annualized compliance cost of more than 1.0 percent to comply with this final action. For more information, please refer to the economic impact analysis that is in the public docket for this rulemaking.

Although this final action will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this final action on small entities by incorporating specific standards for small sulfur recovery plants and streamlining procedures for exempting inherently low-sulfur fuel gases from continuous monitoring.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act (UMRA) of 1995, Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures by State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section

205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this final action 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. As discussed earlier in this preamble, the estimated expenditures for the private sector in the fifth year after proposal are an annualized cost of $31.1 million (2006 dollars). Thus, this final action is not subject to the requirements of section 202 and 205 of the UMRA. In addition, EPA has determined that this final action contains no regulatory requirements that might significantly or uniquely affect small governments. This final action contains no requirements that apply to such governments, imposes no obligations upon them, and would not result in expenditures by them of $100 million or more in any one year or any disproportionate impacts on them. Therefore, this final action is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. None of the affected facilities are owned or operated by State governments. Thus, Executive Order 13132 does not apply to this final action.

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

Executive Order 13175 (65 FR 67249, November 9, 2000) requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' This final action does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. The final rules impose requirements on owners and operators of specified industrial facilities and not tribal governments. Thus, Executive Order 13175 does not apply to this final action.

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

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 rule is not a ''significant energy action'' as defined in Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (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. We prepared an analysis of the impacts on energy markets as part of our RIA for this final action. This analysis accounts for the increase in electricity generation occurring due to additional control requirements associated with this final action. Our analysis shows that there is a reduction in gasoline output of less than 0.75 million gallons per year, or less than 50 barrels of gasoline production per day in the fifth year after proposal of this final action. In addition, our analysis shows that there is no increase in gasoline prices in the fifth year after proposal of this final action. With no increase in domestic gasoline prices, no significant increase in our dependence on foreign energy supplies should take place. Finally, this final action will have no adverse effect on crude oil supply, coal production, electricity production, and energy distribution. Further, we conclude that this final action is not likely to have any adverse energy effects. For more information on this analysis, please refer to the RIA available in the docket for this rulemaking.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law No. 104–113 (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

This rulemaking involves technical standards. EPA has decided to use the VCS ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' for its manual methods of measuring the content of the exhaust gas. These parts of ANSI/ASME PTC 19.10–1981 are acceptable alternatives to EPA Methods 3B, 6, 6A, 7, 7C, and 15A. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990.

The EPA has also decided to use EPA methods 1, 2, 3, 3A, 3B, 5, 5B, 5F, 5I, 6, 6A, 6C, 7, 7A, 7C, 7D, 7E, 10, 10A, 10B, 11, 15, 15A, 16, and 17 (40 CFR part 60, Appendices A–1 through A6); Performance Specifications 1, 2, 3, 4, 4A, 5, 7, and 11 (40 CFR part 60, Appendix B); quality assurance procedures in 40 CFR part 60, Appendix F; and the Gas Processors Association Standard 2377–86, ''Test for Hydrogen

Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes,'' 1986 Revision. While the Agency has identified 22 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 have been 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 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. EPA has determined that these final amendments to 40 CFR part 60, subpart J will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because they do not affect the level of protection provided to human health or the environment. The final amendments are clarifications which do not relax the control measures on sources regulated by the rule and, therefore, will not cause emissions increases from these sources.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of 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 U.S. Senate, the U.S. 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 not a ''major rule'' as defined by 5 U.S.C. 804(2). This final rule will be effective on June 24, 2008.

List of Subjects in 40 CFR Part 60

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

Dated: April 30, 2008.

Stephen L. Johnson,

Administrator.

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

PART 60—[AMENDED]

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

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

Subpart A—[Amended]

■ 2. Section 60.17 is amended by:

■ a. Revising paragraph (h)(4),

■ b. Revising the last sentence of paragraph (m) introductory text, and

■ c. Revising paragraph (m)(1) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(h) * * *

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], IBR approved for § 60.106(e)(2) of subpart J, §§ 60.104a(d)(3), (d)(5), (d)(6), (h)(3), (h)(4), (h)(5), (i)(3), (i)(4), (i)(5), (j)(3), and (j)(4), 60.105a(d)(4), (f)(2), (f)(4), (g)(2), and (g)(4), 60.106a(a)(1)(iii), (a)(2)(iii), (a)(2)(v), (a)(2)(viii), (a)(3)(ii), and (a)(3)(v), and 60.107a(a)(1)(ii), (a)(1)(iv), (a)(2)(ii), (c)(2), (c)(4), and (d)(2) of subpart Ja, Tables 1 and 3 of subpart EEEE, Tables 2 and 4 of subpart FFFF, Table 2 of subpart JJJJ, and §§ 60.4415(a)(2) and 60.4415(a)(3) of subpart KKKK of this part.

* * * * *

(m) * * * You may inspect a copy at EPA's Air and Radiation Docket and Information Center, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20460.

(1) Gas Processors Association Standard 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, 1986 Revision, IBR approved for §§ 60.105(b)(1)(iv), 60.107a(b)(1)(iv), 60.334(h)(1), 60.4360, and 60.4415(a)(1)(ii).

* * * * *

Subpart J—[Amended]

■ 3. Section 60.100 is amended by revising the first sentence in paragraph (a) and revising paragraphs (b) through (d) to read as follows:

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

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants with a design capacity for sulfur feed of 20 long tons per day (LTD) or less. * * *

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section other than a flare as defined in § 60.101a 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 meets the definition of a flare as defined in § 60.101a 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) and (d) of this section.

(c) Any fluid catalytic cracking unit catalyst regenerator under paragraph (b) of this section which commences construction, reconstruction, or modification on or before January 17, 1984, is exempted from § 60.104(b).

(d) Any fluid catalytic cracking unit in which a contact material reacts with petroleum derivatives to improve feedstock quality and in which the contact material is regenerated by burning off coke and/or other deposits and that commences construction, reconstruction, or modification on or before January 17, 1984, is exempt from this subpart.

* * * * *

■ 4. 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 also 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 to comply with the wastewater provisions in § 60.692, 40 CFR 61.343 through 61.348, or 40 CFR 63.647, or the marine tank vessel loading provisions in 40 CFR 63.562 or 40 CFR 63.651.

* * * * *

■ 5. Section 60.102 is amended by revising paragraph (b) to read as follows:

§ 60.102 Standard for particulate matter.

* * * * *

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or solid fossil fuel is burned, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate matter emissions shall not exceed 43 grams per Gigajoule (g/GJ) (0.10 lb/million British thermal units (Btu)) of heat input attributable to such liquid or solid fossil fuel.

■ 6. Section 60.104 is amended by revising paragraphs (b)(1) and (b)(2) to read as follows:

§ 60.104 Standards for sulfur oxides.

* * * * *

(b) * * *

(1) With an add-on control device, reduce SO_2 emissions to the atmosphere by 90 percent or maintain SO_2 emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or

(2) Without the use of an add-on control device to reduce SO_2 emissions, maintain sulfur oxides emissions calculated as SO_2 to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or

* * * * *

■ 7. Section 60.105 is amended by:

■ a. Revising the first sentence of paragraph (a)(3) introductory text;

■ b. Revising paragraph (a)(3)(iv);

■ c. Revising paragraph (a)(4) introductory text;

■ d. Adding paragraph (a)(4)(iv);

■ e. Revising paragraph (a)(8) introductory text;

■ f. Revising paragraph (a)(8)(i); and

■ g. Adding paragraph (b) to read as follows:

§ 60.105 Monitoring of emissions and operations.

(a) * * *

(3) For fuel gas combustion devices subject to § 60.104(a)(1), either an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere or monitoring as provided in paragraph (a)(4) of this section). * * *

* * * * *

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO_2 emissions into the atmosphere from each of the combustion devices.

(4) Instead of the SO_2 monitor in paragraph (a)(3) of this section for fuel gas combustion devices subject to § 60.104(a)(1), an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in any fuel gas combustion device.

* * * * *

(iv) The owner or operator of a fuel gas combustion device is not required to comply with paragraph (a)(3) or (4) of this section for fuel gas streams that are exempt under § 60.104(a)(1) and fuel gas streams combusted in a fuel gas combustion device that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section will be considered inherently low in sulfur content. If the composition of a fuel gas stream changes such that it is no longer exempt under § 60.104(a)(1) or it no longer meets one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section, the owner or operator must begin continuous monitoring under paragraph (a)(3) or (4) of this section within 15 days of the change.

(A) Pilot gas for heaters and flares.

(B) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(C) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, the catalytic reforming unit, the isomerization unit, and HF alkylation process units.

(D) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

* * * * *

(8) An instrument for continuously monitoring and recording concentrations of SO_2 in the gases at both the inlet and outlet of the SO_2 control device from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 90 percent reduction option under § 60.104(b)(1).

(i) The span value of the inlet monitor shall be set at 125 percent of the maximum estimated hourly potential SO_2 emission concentration entering the control device, and the span value of the outlet monitor shall be set at 50 percent of the maximum estimated hourly potential SO_2 emission concentration entering the control device.

* * * * *

(b) An owner or operator may demonstrate that a fuel gas stream combusted in a fuel gas combustion device subject to § 60.104(a)(1) that is not specifically exempted in § 60.105(a)(4)(iv) is inherently low in sulfur. A fuel gas stream that is determined to be low-sulfur is exempt from the monitoring requirements in paragraphs (a)(3) and (4) of this section until there are changes in operating conditions or stream composition.

(1) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(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) to be considered;

(ii) A statement that there are no crossover or entry points for sour gas (high H_2S content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);

(iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppmv. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems,

seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes (''length-of-stain tube'' type measurement) following the ''Gas Processors Association Standard 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes,'' 1986 Revision (incorporated by reference—see § 60.17), with ranges 0–10/0–100 ppm (N = 10/1) to test the applicant fuel gas stream for H_2S; and

(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 (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).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section).

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator will follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the range of concentrations included in the original application, the owner or operator shall conduct an H_2S test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(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 must determine a rolling 365-day average using the stain sampling results; an average H_2S concentration of 5 ppmv must be used for days prior to the operation change.

* * * * *

■ 8. Section 60.106 is amended by revising paragraph (b)(3) introductory text and revising the first sentence of paragraph (e)(2) to read as follows:

§ 60.106 Test methods and procedures.

* * * * *

(b) * * *

(3) The coke burn-off rate (R_c) shall be computed for each run using the following equation:

$$R_c = K_1Q_r\,(\%CO_2 + \%CO) + K_2Q_a - K_3Q_r\,(\%CO/2 + \%CO_2 + \%O_2) + K_3Q_{oxy}\,(\%O_{oxy})$$

Where:

R_c = Coke burn-off rate, kilograms per hour (kg/hr) (lb/hr).

Q_r = Volumetric flow rate of exhaust gas from fluid catalytic cracking unit regenerator before entering the emission control system, dscm/min (dscf/min).

Q_a = Volumetric flow rate of air to fluid catalytic cracking unit regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

Q_{oxy} = Volumetric flow rate of O_2 enriched air to fluid catalytic cracking unit regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

$\%CO_2$ = Carbon dioxide concentration in fluid catalytic cracking unit regenerator exhaust, percent by volume (dry basis).

%CO = CO concentration in FCCU regenerator exhaust, percent by volume (dry basis).

$\%O_2$ = O_2 concentration in fluid catalytic cracking unit regenerator exhaust, percent by volume (dry basis).

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

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)].

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)].

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

* * * * *

(e) * * *

(2) Where emissions are monitored by § 60.105(a)(3), compliance with § 60.104(a)(1) shall be determined using Method 6 or 6C and Method 3 or 3A. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6. * * *

* * * * *

■ 9. Section 60.107 is amended by:

■ a. Revising the first sentence of paragraph (c)(1)(i);

■ b. Redesignating paragraphs (e) and (f) as (f) and (g); and

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

§ 60.107 Reporting and recordkeeping requirements.

* * * * *

(c) * * *

(1) * * *

(i) The average percent reduction and average concentration of sulfur dioxide on a dry, O_2-free basis in the gases discharged to the atmosphere from any fluid cracking unit catalyst regenerator for which the owner or operator seeks to comply with § 60.104(b)(1) is below 90 percent and above 50 ppmv, as measured by the continuous monitoring system prescribed under § 60.105(a)(8), or above 50 ppmv, as measured by the outlet continuous monitoring system prescribed under § 60.105(a)(9). * * *

* * * * *

(e) For each fuel gas stream combusted in a fuel gas combustion device subject to § 60.104(a)(1), if an owner or operator determines that one of the exemptions listed in § 60.105(a)(4)(iv) applies to that fuel gas stream, the owner or operator shall maintain records of the specific exemption chosen for each fuel gas stream. If the owner or operator applies for the exemption described in § 60.105(a)(4)(iv)(D), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

* * * * *

■ 10. Section 60.108 is amended by revising the last sentence of paragraph (e) to read as follows:

§ 60.108 Performance test and compliance provisions.

* * * * *

(e) * * * The owner or operator shall furnish the Administrator with a written notification of the change in the semiannual report required by § 60.107(f).

■ 11. Part 60 is amended by adding subpart Ja to read as follows:

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

Sec.
60.100a Applicability, designation of affected facility, and reconstruction.
60.101a Definitions.
60.102a Emissions limitations.
60.103a Work practice standards.
60.104a Performance tests.
60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).
60.106a Monitoring of emissions and operations for sulfur recovery plants.
60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices.
60.108a Recordkeeping and reporting requirements.
60.109a Delegation of authority.

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

§ 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 flares and process heaters, 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, 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.

(c) For the purposes of this subpart, under § 60.14, a modification to a flare occurs if:

(1) Any new piping from a refinery process unit or fuel gas system is physically connected to the flare (e.g., for direct emergency relief or some form of continuous or intermittent venting); or

(2) A flare is physically altered to increase the flow capacity of the flare.

(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 May 14, 2007. For purposes of this paragraph, ''commenced'' means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.101a Definitions.

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

Coke burn-off means the coke removed from the surface of the FCCU catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.104a.

Contact material means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

Delayed coking unit means 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.

Flare means an open-flame fuel gas combustion device used for burning off unwanted gas or flammable gas and liquids. The flare includes the foundation, flare tip, structural support, burner, igniter, flare controls including air injection or steam injection systems, flame arrestors, knockout pots, piping and header systems.

Flexicoking unit means one or more refinery process units 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 catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery. When *fluid catalyst cracking unit* regenerator exhaust from two separate fluid catalytic cracking units share a common exhaust treatment (e.g., CO boiler or wet scrubber), the *fluid catalytic cracking unit* is a single affected facility.

Fluid coking unit means one or more refinery process units 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 equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent.

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, but does include gases from flexicoking unit gasifiers. *Fuel gas* does not include vapors that are collected and combusted to comply with the wastewater provisions in § 60.692, 40 CFR 61.343 through 61.348, 40 CFR 63.647, or the marine tank vessel loading provisions in 40 CFR 63.562 or 40 CFR 63.651.

Fuel gas combustion device means any equipment, such as process heaters, boilers, and flares, used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

Fuel gas system means a system of compressors, piping, knock-out pots, mix drums, and units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects refinery fuel gas from one or more sources for treatment as necessary prior to combusting in process heaters or boilers. A *fuel gas system* may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the refinery.

Oxidation control system means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide (SO_2) and recycling the SO_2 to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the SO_2 to a sulfur product.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

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.

Process heater means an enclosed combustion device used to transfer heat indirectly to process stream materials (liquids, gases, or solids) or to a heat transfer material for use in a process unit instead of steam.

Process upset gas means any gas generated by a petroleum refinery process unit as a result of upset or malfunction.

Reduced sulfur compounds means hydrogen sulfide (H_2S), carbonyl sulfide, and carbon disulfide.

Reduction control system means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to H_2S and either recycling the H_2S to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the H_2S to a sulfur product.

Refinery process unit means any segment of the petroleum refinery in which a specific processing operation is conducted.

Sulfur pit means the storage vessel in which sulfur that is condensed after each Claus catalytic reactor is initially accumulated and stored. *A sulfur pit* does not include secondary sulfur storage vessels downstream of the initial Claus reactor sulfur pits.

Sulfur recovery plant means all process units which recover sulfur from HS_2 and/or SO_2 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 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.

§ 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 (h) 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.

(b) An owner or operator subject to the provisions of this subpart shall not discharge or cause the discharge into the atmosphere from any FCCU or FCU:

(1) Particulate matter (PM) in excess of the limits in paragraphs (b)(1)(i), (ii), or (iii) of this section.

(i) 1.0 kilogram per Megagram (kg/Mg)(1 pound (lb) per 1,000 lb) coke burn-off or, if a PM continuous emission monitoring system (CEMS) is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each modified or reconstructed FCCU.

(ii) 0.5 gram per kilogram (g/kg) coke burn-off (0.5 lb PM/1,000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air for each newly constructed FCCU.

(iii) 1.0 kg/Mg (1 lb/1,000 lb) coke burn-off; or if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each affected FCU.

(2) Nitrogen oxides (NO_X) in excess of 80 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis.

(3) Sulfur dioxide (SO_2) in excess of 50 ppmv dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis.

(4) Carbon monoxide (CO) in excess of 500 ppmv, dry basis corrected to 0 percent excess air, on an hourly average basis.

(c) The owner or operator of a FCCU or FCU that uses a continuous parameter monitoring system (CPMS) according to § 60.105a(b)(1) shall comply with the applicable control device parameter operating limit in paragraph (c)(1) or (2) of this section.

(1) If the FCCU or FCU is controlled using an electrostatic precipitator:

(i) The 3-hour rolling average total power and secondary current to the entire system must not fall below the level established during the most recent performance test; and

(ii) The daily average exhaust coke burn-off rate must not exceed the level established during the most recent performance test.

(2) If the FCCU or FCU is controlled using a wet scrubber:

(i) The 3-hour rolling average pressure drop must not fall below the level established during the most recent performance test; and

(ii) The 3-hour rolling average liquid-to-gas ratio must not fall below the level established during the most recent performance test.

(d) If an FCCU or FCU uses a continuous opacity monitoring system (COMS) according to the alternative monitoring option in § 60.105a(e), the 3-hour rolling average opacity of emissions from the FCCU or FCU as measured by the COMS must not exceed the site-specific opacity limit established during the most recent performance test.

(e) The owner or operator of a FCCU or FCU that is exempted from the requirement for a CO continuous emissions monitoring system under § 60.105a(h)(3) shall comply with the parameter operating limits in paragraph (e)(1) or (2) of this section.

(1) For a FCCU or FCU with no post-combustion control device:

(i) The hourly average temperature of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(ii) The hourly average oxygen (O_2) concentration of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(2) For a FCCU or FCU with a post-combustion control device:

(i) The hourly average temperature of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(ii) The hourly average O_2 concentration of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(f) Except as provided in paragraph (f)(3), each owner or operator of an affected sulfur recovery plant shall comply with the applicable emission limits in paragraphs (f)(1) or (2) of this section.

(1) For a sulfur recovery plant with a capacity greater than 20 long tons per day (LTD):

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 250 ppmv limit for each process train or release point or comply with a flow rate weighted average of 250 ppmv for all release points from the sulfur recovery plant; or

(ii) For 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 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; or

(iii) For systems using oxygen enrichment, the owner or operator shall calculate the applicable emission limit using Equation 1 of this section:

$$E_{LS} = k_1 \times \left(-0.038 * (\%O_2)^2 + 11.53 * \%O_2 + 25.6\right) \qquad \text{(Eq. 1)}$$

Where:

E_{LS} = Emission rate of SO_2 for large sulfur recovery plant, ppmv;

k_1 = Constant factor for emission limit conversion: k_1 = 1 for converting to SO_2 limit and k_1 = 1.2 for converting to the reduced sulfur compounds limit; and

$\%O_2$ = O_2 concentration to the SRP, percent by volume (dry basis).

(2) For a sulfur recovery plant with a capacity of 20 LTD or less:

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 2,500 ppm by volume (dry basis) of SO_2 at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 2,500 ppmv limit for each process train or release point or comply with a flow rate weighted average of 2,500 ppmv for all release points from the sulfur recovery plant; or

(ii) For 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 3,000 ppm by volume of reduced sulfur compounds and 100 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air; or

(iii) For systems using oxygen enrichment, the owner or operator shall calculate the applicable emission limit using Equation 2 of this section:

$$E_{SS} = k_1 \times \left(-0.38 * (\%O_2)^2 + 115.3 * \%O_2 + 256\right) \qquad \text{(Eq. 2)}$$

Where:

E_{SS} = Emission rate of SO_2 for small sulfur recovery plant, ppmv.

(3) Periods of maintenance of the sulfur pit, during which the emission limits in paragraphs (f)(1) and (2) shall not apply, shall not exceed 240 hours per year. The owner or operator must document the time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods. Examples of these measures include not adding fresh sulfur or shutting off vent fans.

(g) Each owner or operator of an affected fuel gas combustion device shall comply with the emission limits in paragraphs (g)(1) through (3) of this section.

(1) 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 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.

(2) For each process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr), the owner or operator shall not discharge to the atmosphere any emissions of NO_X in excess of 40 ppmv (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis.

(3) Except as provided in paragraphs (h) and (i) of this section, the owner or operator of an affected flare shall not allow flow to each affected flare during normal operations of more than 7,080 standard cubic meters per day (m^3/day) (250,000 standard cubic feet per day (scfd)) on a 30-day rolling average. The owner or operator of a newly constructed or reconstructed flare shall comply with the emission limit in this paragraph by no later than the date that flare becomes an affected flare subject to this subpart. The owner or operator of a modified flare shall comply with the emission limit in this paragraph by no later than 1 year after that flare becomes an affected flare subject to this subpart.

(h) 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 paragraph (g) of this section.

(i) In periods of fuel gas imbalance that are described in the flare management plan required in section 60.103a(a), compliance with the emission limit in paragraph (g)(3) of this section is demonstrated by following the procedures and maintaining records described in the flare management plan to document the periods of excess fuel gas.

§ 60.103a Work practice standards.

(a) Each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management plan. 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 flare becomes an affected flare subject to this subpart. The owner or operator of a modified flare must develop and implement the flare management plan by no later than 1 year after the flare becomes an affected flare subject to this subpart. The plan must include:

(1) A diagram illustrating all connections to the flare;

(2) Methods for monitoring flow rate to the flare, including 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 for flare gas monitoring devices;

(3) Procedures to minimize discharges to the flare gas system during the planned start-up and shutdown of the refinery process units that are connected to the affected flare;

(4) Procedures to conduct a root cause analysis of any process upset or malfunction that causes a discharge to the flare in excess of 14,160 m^3/day (500,000 scfd);

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

(6) Explanation of procedures to follow during times that the flare must exceed the limit in § 60.102a(g)(3) (e.g., keep records of natural gas purchases to support assertion that the refinery is producing more fuel gas than needed to operate the processes).

(b) Each owner or operator that operates a fuel gas combustion device or sulfur recovery plant subject to this subpart shall conduct a root cause analysis of any emission limit exceedance or process start-up, shutdown, upset, or malfunction that causes a discharge to the atmosphere in excess of 227 kilograms per day (kg/day) (500 lb per day (lb/day)) of SO_2. For any root cause analysis performed, the owner or operator shall record the identification of the affected facility, the date and duration of the discharge, the results of the root cause analysis, and the action taken as a result of the root cause analysis. The first root cause analysis for a modified flare must be conducted no later than the first discharge that occurs after the flare has been an affected flare subject to this subpart for 1 year.

(c) Each owner or operator of a delayed coking unit shall depressure to 5 lb per square inch gauge (psig) during reactor vessel depressuring and vent the exhaust gases to the fuel gas system for combustion in a fuel gas combustion device.

§ 60.104a Performance tests.

(a) The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant, and fuel gas combustion device to demonstrate initial compliance with each applicable emissions limit in § 60.102a 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.

(b) The owner or operator of a FCCU or FCU that elects to monitor control device operating parameters according to the requirements in § 60.105a(b), to use bag leak detectors according to the requirements in § 60.105a(c), or to use COMS according to the requirements in § 60.105a(e) shall conduct a PM performance test at least once every 12 months and furnish the Administrator a written report of the results of each test.

(c) In conducting the performance tests required by this subpart (or as requested by the Administrator), the owner or operator shall use the test methods in 40 CFR part 60, Appendices A–1 through A–8 or other methods as specified in this section, except as provided in § 60.8(b).

(d) The owner or operator shall determine compliance with the PM, NO_X, SO_2, and CO emissions limits in § 60.102a(b) for FCCU and FCU using the following methods and procedures:

(1) Method 1 of Appendix A–1 to part 60 for sample and velocity traverses.

(2) Method 2 of Appendix A–1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of Appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(4) Method 5, 5B, or 5F of Appendix A–3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU without a wet scrubber subject to the emissions limit in § 63.102a(b)(1). Use Method 5 or 5B of Appendix A–3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU with a wet scrubber subject to the emissions limit in § 63.102a(b)(1).

(i) The PM performance test consists of 3 valid test runs; the duration of each test run must be no less than 60 minutes.

(ii) The emissions rate of PM (E_{PM}) is computed for each run using Equation 3 of this section:

$$E = \frac{c_s \, Q_{sd}}{K \, R_c} \qquad \text{(Eq. 3)}$$

Where:

E = Emission rate of PM, g/kg, lbs per 1,000 lbs (lb/1,000 lbs) 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), lbs per hour (lbs/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 4 of this section:

$$R_c = K_1 Q_r \left(\%CO_2 + \%CO\right) + K_2 Q_a - K_3 Q_r \left(\%CO/2 + \%CO_2 + \%O_2\right) + K_3 Q_{oxy} \left(\%O_{oxy}\right) \qquad \text{(Eq. 4)}$$

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 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-dsc-%) [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-%)].

(iv) During the performance test, the volumetric flow rate of exhaust gas from catalyst regenerator (Q_r) before any emission control or energy recovery system that burns auxiliary fuel is measured using Method 2 of Appendix A–1 to part 60.

(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 in § 60.105a(b)(2), if applicable, using Equation 5 of this section:

$$Q_r = \frac{79 \times Q_a + (100 - \%Oxy) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. 5)}$$

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(g)(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).

(5) Method 6, 6A, or 6C of Appendix A–4 to part 60 for moisture content and for the concentration of SO_2; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of Appendix A–4 to part 60.

(6) Method 7, 7A, 7C, 7D, or 7E of Appendix A–4 to part 60 for moisture content and for the concentration of NO_X calculated as nitrogen dioxide (NO_2); the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of Appendix A–4 to part 60.

(7) Method 10, 10A, or 10B of Appendix A–4 to part 60 for moisture content and for the concentration of CO. The sampling time for each run must be 60 minutes.

(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 6 of this section:

$$C_{adj} = C_{meas}\left[\frac{20.9_c}{(20.9 - \%O_2)}\right] \qquad \text{(Eq. 6)}$$

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.

(e) The owner or operator of a FCCU or FCU that is controlled by an electrostatic precipitator or wet scrubber and that is subject to control device operating parameter limits in § 60.102a(c) shall establish the limits based on the performance test results according to the following procedures:

(1) Reduce the parameter monitoring data to hourly averages for each test run;

(2) Determine the hourly average operating limit for each required parameter as the average of the three test runs.

(f) The owner or operator of an FCCU or FCU that uses cyclones to comply with the PM limit in § 60.102a(b)(1) and elects to comply with the COMS alternative monitoring option in § 60.105a(d) shall establish a site-specific opacity operating limit according to the procedures in paragraphs (f)(1) through (3) of this section.

(1) Collect COMS data every 10 seconds during the entire period of the PM performance test and reduce the data to 6-minute averages.

(2) Determine and record the hourly average opacity from all the 6-minute averages.

(3) Compute the site-specific limit using Equation 7 of this section:

$$Opacity\ Limit = Opacity_{st} x \left(\frac{1lb/1{,}000\ lb\ coke\ burn}{PMEmR_{st}}\right) \qquad \text{(Eq. 7)}$$

Where:

Opacity limit = Maximum permissible hourly average opacity, percent, or 10 percent, whichever is greater;

$Opacity_{st}$ = Hourly average opacity measured during the source test runs, percent; and

$PMEmR_{st}$ = PM emission rate measured during the source test, lb/1,000 lbs coke burn.

(g) The owner or operator of a FCCU or FCU that is exempt from the requirement to install and operate a CO CEMS pursuant to § 60.105a(h)(3) and that is subject to control device operating parameter limits in § 60.102a(c) shall establish the limits based on the performance test results

using the procedures in paragraphs (g)(1) and (2) of this section.

(1) Reduce the temperature and O_2 concentrations from the parameter monitoring systems to hourly averages for each test run.

(2) Determine the operating limit for temperature and O_2 concentrations as the average of the average temperature and O_2 concentration for the three test runs.

(h) The owner or operator shall determine compliance with the SO_2 and H_2S emissions limits for sulfur recovery plants in §§ 60.102a(f)(1)(i), 60.102a(f)(1)(iii), 60.102a(f)(1)(iii), 60.102a(f)(2)(i), and 60.102a(f)(2)(iii) and the reduced sulfur compounds and H_2S emissions limits for sulfur recovery plants in § 60.102a(f)(1)(ii) and § 60.102a(f)(2)(ii) using the following methods and procedures:

(1) Method 1 of Appendix A–1 to part 60 for sample and velocity traverses.

(2) Method 2 of Appendix A–1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of Appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(4) Method 6, 6A, or 6C of Appendix A–4 to part 60 to determine the SO_2 concentration. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of Appendix A–4 to part 60.

(5) Method 15 or 15A of Appendix A–5 to part 60 or Method 16 of Appendix A–6 to part 60 to determine the reduced sulfur compounds and H_2S concentrations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(i) Each run consists of 16 samples taken over a minimum of 3 hours.

(ii) The owner or operator shall calculate the average H_2S concentration after correcting for moisture and O_2 as the arithmetic average of the H_2S concentration for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iii) The owner or operator shall calculate the SO_2 equivalent for each run after correcting for moisture and O_2 as the arithmetic average of the SO_2 equivalent of reduced sulfur compounds for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iv) The owner or operator shall use Equation 6 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:

(1) Method 1 of Appendix A–1 to part 60 for sample and velocity traverses;

(2) Method 2 of Appendix A–1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of Appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60;

(4) Method 6, 6A, or 6C of Appendix A–4 to part 60 to determine the SO_2 concentration. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of Appendix A–4 to part 60.

(i) The performance test consists of 3 valid test runs; the duration of each test run must be no less than 1 hour.

(ii) If a single fuel gas combustion device having a common source of fuel gas is monitored as allowed under § 60.107a(a)(1)(v), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

(5) Method 7, 7A, 7C, 7D, or 7E of Appendix A–4 to part 60 for moisture content and for the concentration of NO_X calculated as NO_2; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of Appendix A–4 to part 60.

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

(1) Method 1 of Appendix A–1 to part 60 for sample and velocity traverses;

(2) Method 2 of Appendix A–1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of Appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60;

(4) Method 11, 15, or 15A of Appendix A–5 to part 60 or Method 16 of Appendix A–6 to part 60 for determining the H_2S concentration for affected plants using an H_2S monitor as specified in § 60.107a(a)(2). The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (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 for each individual fuel gas stream used in the fuel gas combustion device.

(i) For Method 11 of Appendix A–5 to part 60, the sampling time and sample volume must be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times must be taken at about 1-hour intervals. The arithmetic average of these two samples constitutes a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

(ii) For Method 15 of Appendix A–5 to part 60, at least three injects over a 1-hour period constitutes a run.

(iii) For Method 15A of Appendix A–5 to part 60, a 1-hour sample constitutes a run. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(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 is added to a common source of fuel gas that previously demonstrated compliance.

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

(a) *FCCU and FCU subject to PM emissions limit*. Each owner or operator subject to the provisions of this subpart shall monitor each FCCU and FCU subject to the PM emissions limit in § 60.102a(b)(1) according to the requirements in paragraph (b), (c), (d), or (e) of this section.

(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) shall comply with the requirements in paragraphs (b)(1) through (3) 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 requirements in paragraph (b)(1)(i) through (iii) of this section.

(i) For units controlled using an electrostatic precipitator, the owner or operator shall use CPMS to measure and record the hourly average total power input and secondary voltage to the entire system.

(ii) For units controlled using a wet scrubber, the owner or operator shall use CPMS to measure and record the hourly average pressure drop, liquid feed rate, and exhaust gas flow rate. As an alternative to a CPMS, the owner or operator must comply with the requirements in either paragraph (b)(1)(ii)(A) or (B) of this section.

(A) As an alterative 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.

(B) As an alternative to exhaust gas flow rate, the owner or operator shall comply with the approved alternative for monitoring exhaust gas flow rate in 40 CFR 63.1573(a) of the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

(iii) The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications and requirements.

(iv) The owner or operator shall determine and record the average coke burn-off rate and hours of operation for each FCCU or FCU using the procedures in § 60.104a(d)(4)(iii).

(v) If you use a control device other than an electrostatic precipitator, wet scrubber, fabric filter, or cyclone, you may request approval to monitor parameters other than those required in paragraph (b)(1) of this section by submitting an alternative monitoring plan to the Administrator. The request must include the information in paragraphs (b)(1)(v)(A) through (E) of this section.

(A) A description of each affected facility and the parameter(s) to be monitored to determine whether the affected facility will continuously comply with the emission limitations and an explanation of the criteria used to select the parameter(s).

(B) A description of the methods and procedures that will be used to demonstrate that the parameter(s) can be used to determine whether the affected facility will continuously comply with the emission limitations and the schedule for this demonstration. The owner or operator must certify that an operating limit will be established for the monitored parameter(s) that represents the conditions in existence when the control device is being properly operated and maintained to meet the emission limitation.

(C) The frequency and content of the recordkeeping, recording, and reporting, if monitoring and recording are not continuous. The owner or operator also must include the rationale for the proposed monitoring, recording, and reporting requirements.

(D) Supporting calculations.

(E) Averaging time for the alternative operating parameter.

(2) For use in determining the coke burn-off rate for an FCCU or FCU, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring the concentrations of CO_2, O_2 (dry basis), and if needed, CO in the exhaust gases prior to any control or energy recovery system that burns auxiliary fuels.

(i) The owner or operator shall install, operate, and maintain each monitor according to Performance Specification 3 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 Specification 3 of Appendix B to part 60. The owner or operator shall use Method 3 of Appendix A–3 to part 60 for conducting the relative accuracy evaluations.

(iii) The owner or operator shall comply with the quality assurance requirements of procedure 1 of Appendix F to part 60, including quarterly accuracy determinations for CO_2 and CO monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(c) *Bag leak detection systems.* Each owner or operator shall install, operate, and maintain a bag leak detection system for each baghouse or similar fabric filter control device that is used to comply with the PM per coke burn-off emissions limit in § 60.102a(b)(1) for an FCCU or FCU according to paragraph (c)(1) of this section; prepare and operate by a site-specific monitoring plan according to paragraph (c)(2) of this section; take action according to paragraph (c)(3) of this section; and record information according to paragraph (c)(4) of this section.

(1) Each bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 0.00044 grains per actual cubic foot or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(1)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.

(vii) The owner or operator shall install the bag leak detection sensor downstream of the baghouse and upstream of any wet scrubber.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) The owner or operator shall develop and submit to the Administrator for approval a site-specific monitoring plan for each baghouse and bag leak detection system. The owner or operator shall operate and maintain each baghouse and bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (vii) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored;

(vi) Procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable; and

(vii) How the baghouse system will be operated and maintained, including monitoring of pressure drop across baghouse cells and frequency of visual inspections of the baghouse interior and baghouse components such as fans and dust removal and bag cleaning mechanisms.

(3) For each bag leak detection system, the owner or operator shall initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator shall alleviate the cause of the alarm within 3 hours of the alarm by taking whatever action(s) are necessary. Actions may include, but are not limited to the following:

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective baghouse compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the particulate emissions.

(4) The owner or operator shall maintain records of the information specified in paragraphs (c)(4)(i) through (iii) of this section for each bag leak detection system.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the alarm was alleviated within 3 hours of the alarm.

(d) *Continuous emissions monitoring systems (CEMS).* An owner or operator subject to the PM concentration emission limit (in gr/dscf) in § 60.102a(b)(1) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (0 percent excess air) of PM in the exhaust gases prior to release to the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each PM monitor according to Performance Specification 11 of appendix B to part 60. The span value of this PM monitor is 0.08 gr/dscf PM.

(2) The owner or operator shall conduct performance evaluations of each PM monitor according to the requirements in § 60.13(c) and Performance Specification 11 of appendix B to part 60. The owner or operator shall use EPA Methods 5 or 5I of Appendix A–3 to part 60 or Method 17 of Appendix A–6 to part 60 for conducting the relative accuracy evaluations.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in § 60.13(c) and Performance Specification 3 of Appendix B to part 60. Method 3, 3A, or 3B of Appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 2 of Appendix B to part 60 for each PM CEMS and Procedure 1 of Appendix F to part 60 for each O_2 monitor, including quarterly accuracy determinations for each PM monitor, annual accuracy determinations for each O_2 monitor, and daily calibration drift tests.

(e) *Alternative monitoring option for FCCU and FCU—COMS.* Each owner or operator of an FCCU or FCU that uses cyclones to comply with the PM emission limit in § 60.102a(b)(1) shall monitor the opacity of emissions according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The owner or operator shall install, operate, and maintain an instrument for continuously monitoring and recording the opacity of emissions from the FCCU or the FCU exhaust vent.

(2) The owner or operator shall install, operate, and maintain each COMS according to Performance Specification 1 of Appendix B to part 60. The instrument shall be spanned at 20 to 60 percent opacity.

(3) The owner or operator shall conduct performance evaluations of each COMS according to § 60.13(c) and Performance Specification 1 of Appendix B to part 60.

(f) *FCCU and FCU subject to NO_X limit.* Each owner or operator subject to the NO_X emissions limit in § 60.102a(b)(2) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of NO_X emissions into the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air.

(1) 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 is 200 ppmv NO_X.

(2) The owner or operator shall conduct performance evaluations of each NO_X monitor according to the requirements in § 60.13(c) and Performance Specification 2 of Appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of Appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas

Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of Appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of Appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in § 60.13(c) and Performance Specification 3 of Appendix B to part 60. Method 3, 3A, or 3B of Appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 1 of Appendix F to part 60 for each NO_X and O_2 monitor, including quarterly accuracy determinations for NO_X monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(g) *FCCU and FCU subject to SO_2 limit*. The owner or operator subject to the SO_2 emissions limit in § 60.102a(b)(3) for an FCCU or an FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, corrected to 0 percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an O_2 monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each SO_2 monitor according to Performance Specification 2 of Appendix B to part 60. The span value of this SO_2 monitor is 200 ppmv SO_2.

(2) The owner or operator shall conduct performance evaluations of each SO_2 monitor according to the requirements in § 60.13(c) and Performance Specification 2 of Appendix B to part 60. The owner or operator shall use Methods 6, 6A, or 6C of Appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI / ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of Appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of Appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in § 60.13(c) and Performance Specification 3 of Appendix B to part 60. Method 3, 3A, or 3B of Appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of Appendix F to part 60 for each SO_2 and O_2 monitor, including quarterly accuracy determinations for SO_2 monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(h) *FCCU and fluid coking units subject to CO emissions limit*. Except as specified in paragraph (h)(3) of this section, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere from each FCCU and FCU subject to the CO emissions limit in § 60.102a(b)(4).

(1) The owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of Appendix B to part 60. The span value for this instrument is 1,000 ppm CO.

(2) The owner or operator shall conduct performance evaluations of each CO monitor according to the requirements in § 60.13(c) and Performance Specification 4 or 4A of Appendix B to part 60. The owner or operator shall use Methods 10, 10A, or 10B of Appendix A–4 to part 60 for conducting the relative accuracy evaluations.

(3) A CO CEMS need not be installed if the owner or operator demonstrates that all hourly average CO emissions are and will remain less than 50 ppmv (dry basis) corrected to 0 percent excess air. The Administrator may revoke this exemption from monitoring upon a determination that CO emissions on an hourly average basis have exceeded 50 ppmv (dry basis) corrected to 0 percent excess air, in which case a CO CEMS shall be installed within 180 days.

(i) The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that meets the requirements of Performance Specification 4 or 4A of Appendix B to part 60. The span value shall be 100 ppm CO instead of 1,000 ppm, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 of Appendix A–4 to part 60 and employ the sample conditioning system of Method 10A of Appendix A–4 to part 60, the alternative relative accuracy test procedure in section 10.1 of Performance Specification 2 of Appendix B to part 60 may be used in place of the relative accuracy test.

(ii) The owner or operator must submit the following information to the Administrator:

(A) The measurement data specified in paragraph (h)(3)(i) of this section along with all other operating data known to affect CO emissions; and

(B) Descriptions of the CPMS for exhaust gas temperature and O_2 monitor required in paragraph (h)(4) of this section and operating limits for those parameters to ensure combustion conditions remain similar to those that exist during the demonstration period.

(iii) The effective date of the exemption from installation and operation of a CO CEMS is the date of submission of the information and data required in paragraph (h)(3)(ii) of this section.

(4) The owner or operator of a FCCU or FCU that is exempted from the requirement to install and operate a CO CEMS in paragraph (h)(3) of this section shall install, operate, calibrate, and maintain CPMS to measure and record the operating parameters in paragraph (h)(4)(i) or (ii) of this section. The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications.

(i) For a FCCU or FCU with no post-combustion control device, the temperature and O_2 concentration of the exhaust gas stream exiting the unit.

(ii) For a FCCU or FCU with a post-combustion control device, the temperature and O_2 concentration of the exhaust gas stream exiting the control device.

(i) *Excess emissions*. For the purpose of reports required by § 60.7(c), periods of excess emissions for a FCCU or FCU subject to the emissions limitations in § 60.102a(b) are defined as specified in paragraphs (i)(1) through (6) of this section. Note: Determine all averages, except for opacity, as the arithmetic average of the applicable 1-hour averages, *e.g.*, determine the rolling 3-hour average as the arithmetic average of three contiguous 1-hour averages.

(1) If a CPMS is used according to § 60.105a(b)(1), all 3-hour periods during which the average PM control device operating characteristics, as measured by the continuous monitoring systems under § 60.105a(b)(1), fall below the levels established during the performance test.

(2) If a PM CEMS is used according to § 60.105a(d), all 7-day periods during which the average PM emission rate, as measured by the continuous PM monitoring system under § 60.105a(d) exceeds 0.040 gr/dscf corrected to 0 percent excess air for a modified or reconstructed FCCU, 0.020 gr/dscf corrected to 0 percent excess air for a newly constructed FCCU, or 0.040 gr/dscf for an affected fluid coking unit.

(3) If a COMS is used according to § 60.105a(e), all 3-hour periods during which the average opacity, as measured by the COMS under § 60.105a(e), exceeds the site-specific limit established during the most recent performance test.

(4) All rolling 7-day periods during which the average concentration of NO_X as measured by the NO_X CEMS under § 60.105a(f) exceeds 80 ppmv for an affected FCCU or FCU.

(5) Except as provided in paragraph (i)(7) of this section, 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.

(6) All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under §1A60.105a(h) exceeds 500 ppmv or, if applicable, all 1-hour periods during which the average temperature and O_2 concentration as measured by the continuous monitoring systems under § 60.105a(h)(4) fall below the operating limits established during the performance test.

§ 60.106a Monitoring of emissions and operations for sulfur recovery plants.

(a) The owner or operator of a sulfur recovery plant that is subject to the emissions limits in § 60.102a(f)(1) or § 60.102a(f)(2) shall:

(1) For sulfur recovery plants subject to the SO_2 emission limit in § 60.102a(f)(1)(i) or § 60.102a(f)(2)(i), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of any SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are two times the applicable SO_2 emission limit and between 10 and 25 percent O_2, inclusive.

(ii) The owner or operator shall install, operate, and maintain each SO_2 CEMS according to Performance Specification 2 of Appendix B to part 60.

(iii) The owner or operator shall conduct performance evaluations of each SO_2 monitor according to the requirements in § 60.13(c) and Performance Specification 2 of Appendix B to part 60. The owner or operator shall use Methods 6 or 6C of Appendix A–4 to part 60 and Method 3 or 3A of Appendix A–2 of part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6.

(2) For sulfur recovery plants that are subject to the reduced sulfur compound and H_2S emission limit in § 60.102a(f)(1)(ii) or § 60.102a(f)(2)(ii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of reduced sulfur, H_2S, and O_2 emissions into the atmosphere. The reduced sulfur emissions shall be calculated as SO_2 (dry basis, zero percent excess air).

(i) The span values for this monitor are two times the applicable reduced sulfur emission limit, two times the H_2S emission limit, and between 10 and 25 percent O_2, inclusive.

(ii) The owner or operator shall install, operate, and maintain each reduced sulfur CEMS according to Performance Specification 5 of Appendix B to part 60.

(iii) The owner or operator shall conduct performance evaluations of each reduced sulfur monitor according to the requirements in § 60.13(c) and Performance Specification 5 of Appendix B to part 60. The owner or operator shall use Methods 15 or 15A of Appendix A–5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(iv) The owner or operator shall install, operate, and maintain each H_2S CEMS according to Performance Specification 7 of Appendix B to part 60.

(v) The owner or operator shall conduct performance evaluations of each reduced sulfur monitor according to the requirements in § 60.13(c) and Performance Specification 5 of Appendix B to part 60. The owner or operator shall use Methods 11, 15, or 15A of Appendix A–5 to part 60 or Method 16 of Appendix A–6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(vi) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of Appendix B to part 60.

(vii) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(viii) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of § 60.13(c) and Performance Specification 3 of Appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of Appendix A–2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(ix) The owner or operator shall comply with the applicable quality assurance procedures of Appendix F to part 60 for each monitor, including annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(3) In place of the reduced sulfur monitor required in paragraph (a)(2) of this section, the owner or operator shall install, calibrate, operate, and maintain an instrument using an air or O_2 dilution and oxidation system to convert any reduced sulfur to SO_2 for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of the total resultant SO_2. The monitor must include an O_2 monitor for correcting the data for excess O_2.

(i) The span value for this monitor is two times the applicable SO_2 emission limit.

(ii) The owner or operator shall conduct performance evaluations of each SO_2 monitor according to the requirements in § 60.13(c) and Performance Specification 5 of Appendix B to part 60. The owner or operator shall use Methods 15 or 15A of

Appendix A–5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(iii) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of Appendix B to part 60.

(iv) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(v) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of § 60.13(c) and Performance Specification 3 of Appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of Appendix A–2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(vi) The owner or operator shall comply with the applicable quality assurance procedures of Appendix F to part 60 for each monitor, including quarterly accuracy determinations for each SO_2 monitor, annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(b) *Excess emissions*. For the purpose of reports required by § 60.7(c), periods of excess emissions for sulfur recovery plants subject to the emissions limitations in § 60.102a(f) are defined as specified in paragraphs (b)(1) through (3) of this section. **Note:** Determine all averages as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 12-hour average as the arithmetic average of 12 contiguous 1-hour averages.

(1) All 12-hour periods 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 the applicable emission limit (dry basis, zero percent excess air); or

(2) All 12-hour periods during which the average concentration of reduced sulfur (as SO_2) as measured by the reduced sulfur continuous monitoring system required under paragraph (a)(2) of this section exceeds the applicable emission limit; or

(3) All 12-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under paragraph (a)(2) of this section exceeds the applicable emission limit (dry basis, 0 percent excess air).

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

(a) *Fuel gas combustion devices subject to SO_2 or H_2S limit.* The owner or operator of a fuel gas combustion device that is subject to the requirements in § 60.102a(g) shall comply with the requirements in paragraph (a)(1) of this section for SO_2 emissions or paragraph (a)(2) of this section for H_2S emissions.

(1) The owner or operator of a fuel gas combustion device subject to 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.

(i) The owner or operator shall install, operate, and maintain each SO_2 monitor according to Performance Specification 2 of Appendix B to part 60. The span value for the SO_2 monitor is 50 ppm SO_2.

(ii) The owner or operator shall conduct performance evaluations for the SO_2 monitor according to the requirements of § 60.13(c) and Performance Specification 2 of Appendix B to part 60. The owner or operator shall use Methods 6, 6A, or 6C of Appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of Appendix A–4 to part 60. Samples taken by Method 6 of Appendix A–4 to part 60 shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iii) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of Appendix B to part 60. The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(iv) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of § 60.13(c) and Performance Specification 3 of Appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of Appendix A–2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(v) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part 60, including quarterly accuracy determinations for SO_2 monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(vi) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO_2 emissions into the atmosphere from each of the combustion devices.

(2) The owner or operator of a fuel gas combustion device subject to the H_2S concentration limits in § 60.102a(g)(1)(ii) 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.

(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 320 ppmv H_2S.

(ii) The owner or operator shall conduct performance evaluations for each H_2S monitor according to the requirements of § 60.13(c) and Performance Specification 7 of Appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of Appendix A–5 to part 60 or Method 16 of Appendix A–6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(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) Fuel gas combustion devices 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.

(3) The owner or operator of a fuel gas combustion device is not required to comply with paragraph (a)(1) or (2) of this section for fuel gas streams that are

exempt under § 60.102a(h) and fuel gas streams combusted in a process heater or other fuel gas combustion device 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.

(i) Pilot gas for heaters and flares.

(ii) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(iii) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, catalytic reforming unit, isomerization unit, and HF alkylation process units.

(iv) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

(4) If the composition of an exempt fuel gas stream changes, the owner or operator must follow the procedures in paragraph (b)(3) of this section.

(b) *Exemption from H_2S monitoring requirements for low-sulfur fuel gas streams.* The owner or operator of a fuel gas combustion device 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) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(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) to be considered;

(ii) A statement that there are no crossover or entry points for sour gas (high H_2S content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);

(iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppm H_2S. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes (''length-of-stain tube'' type measurement) following the ''Gas Processors Association Standard 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes,'' 1986 Revision (incorporated by reference—see § 60.17), with ranges 0–10/0–100 ppm (N = 10/1) to test the applicant fuel gas stream for H_2S; and

(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 (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).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section.

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator shall follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the range of concentrations included in the original application, the owner or operator shall conduct an H_2S test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(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 must determine a rolling 365-day average using the stain sampling results; an average H_2S concentration of 5 ppmv must be used for days prior to the operation change.

(c) *Process heaters subject to NO_X limit.* The owner or operator of a process heater subject to the NO_X emission limit in § 60.102a(g)(2) 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. The monitor must include an O_2 monitor for correcting the data for excess air.

(1) 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 is 200 ppmv NO_X.

(2) The owner or operator shall conduct performance evaluations of each NO_X monitor according to the requirements in § 60.13(c) and Performance Specification 2 of Appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of Appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of Appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of Appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in § 60.13(c) and

Performance Specification 3 of Appendix B to part 60. Method 3, 3A, or 3B of Appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of Appendix F to part 60 for each NO_X and O_2 monitor, including quarterly accuracy determinations for NO_X monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(6) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with low-NO_X burners (LNB) or ultra low-NO_X burners (ULNB) is not subject to the monitoring requirements in paragraphs (c)(1) through (5) of this section. The owner or operator of such a process heater must conduct biennial performance tests to demonstrate compliance.

(d) *Sulfur monitoring for affected flares.* The owner or operator of an affected flare subject to § 60.103a(b) shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of reduced sulfur in flare gas. The owner or operator of a modified flare shall install this instrument by no later than 1 year after the flare becomes an affected flare subject to this subpart.

(1) The owner or operator shall install, operate, and maintain each reduced sulfur CEMS according to Performance Specification 5 of Appendix B to part 60.

(2) The owner or operator shall conduct performance evaluations of each reduced sulfur monitor according to the requirements in § 60.13(c) and Performance Specification 5 of Appendix B to part 60. The owner or operator shall use Methods 15 or 15A of Appendix A–5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

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

(e) *Flow monitoring for flares.* The owner or operator of an affected flare subject to § 60.102a(g)(3) shall install, operate, calibrate, and maintain CPMS to measure and record the exhaust gas flow rate. The owner or operator of a modified flare shall install this instrument by no later than 1 year after the flare becomes an affected flare subject to this subpart.

(1) The CPMS must be able to correct for the temperature and pressure of the system and output flow in standard conditions as defined in § 60.2.

(2) The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications and requirements.

(f) *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) are defined as specified in paragraphs (f)(1) through (4) of this section. **Note:** Determine all averages as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 3-hour average as the arithmetic average of three contiguous 1-hour averages.

(1) All rolling 3-hour periods 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 all rolling 365-day periods during which the average concentration as measured by the SO_2 continuous monitoring system required under paragraph (a)(1) of this section exceeds 8 ppmv; or

(2) All rolling 3-hour periods 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, all days in which the concentration of H_2S as measured by daily stain tube sampling required under paragraph (b)(3)(iii) of this section exceeds 162 ppmv, and all rolling 365-day periods during which the average concentration as measured by the H_2S continuous monitoring system under paragraph (a)(2) of this section exceeds 60 ppmv.

(3) All rolling 24-hour periods during which the average concentration of NO_X as measured by the NO_X continuous monitoring system required under paragraph (c) of this section exceeds 40 ppmv.

(4) All rolling 30-day periods during which the average flow rate to an affected flare as measured by the monitoring system required under paragraph (e) of this section exceeds 250,000 scfd.

§ 60.108a Recordkeeping and reporting requirements.

(a) Each owner or operator subject to the emissions limitations in § 60.102a shall comply with the notification, recordkeeping, and reporting requirements in § 60.7 and other requirements as specified in this section.

(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 seeks to comply. Notification shall be submitted with the notification of initial startup required by § 60.7(a)(3).

(c) The owner or operator shall maintain the following records:

(1) A copy of the flare management plan and each root cause analysis of a discharge;

(2) Records of information to document conformance with bag leak detection system operation and maintenance requirements in § 60.105a(c).

(3) Records of bag leak detection system alarms and actions according to § 60.105a(c).

(4) For each FCCU and fluid coking unit subject to the monitoring requirements in § 60.105a(b)(1), records of the average coke burn-off rate and hours of operation.

(5) For each fuel gas stream to which one of the exemptions listed in § 60.107a(a)(3) applies, records of the specific exemption determined to apply for each fuel stream. If the owner or operator applies for the exemption described in § 60.107a(a)(3)(iv), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

(6) The owner or operator shall record and maintain records of discharges greater than 500 lb/day SO_2 from any affected fuel gas combustion device or sulfur recovery plant and discharges to an affected flare in excess of 500,000 scfd. These records shall include:

(i) A description of the discharge.

(ii) For discharges greater than 500 lb/day SO_2, 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. Engineering calculations are allowed for fuel gas combustion devices other than flares.

(iv) For discharges greater than 500 lb/day SO_2, the measured or estimated

concentration of H_2S, TRS and SO_2 of the stream discharged. Process knowledge can be used to make these estimates for fuel gas combustion devices other than flares.

(v) For discharges greater than 500 lb/day SO_2, 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 to SO_2. For other fuel gas combustion devices, assume 99 percent conversion of H_2S to SO_2.

(vi) Results of any root-cause analysis conducted as required in § 60.103a(a)(4) and § 60.103a(b).

(d) Each owner or operator subject to this subpart shall submit an excess emissions report for all periods of excess emissions according to the requirements of § 60.7(c) except that the report shall contain the information specified in paragraphs (d)(1) through (7) of this section.

(1) The date that the exceedance occurred;

(2) An explanation of the exceedance;

(3) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and

(4) A description of the action taken, if any.

(5) A root-cause summary report that provides the information described in paragraph (e)(6) of this section for all discharges for which a root-cause analysis was required by § 60.103a(a)(4) and § 60.103a(b).

(6) For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(7) A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.

§ 60.109a Delegation of authority.

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency within your State.

(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 (3) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(1) Approval of a major change to test methods under § 60.8(b). A ''major change to test method'' is defined in 40 CFR 63.90.

(2) Approval of a major change to monitoring under § 60.13(i). A ''major change to monitoring'' is defined in 40 CFR 63.90.

(3) Approval of a major change to recordkeeping/reporting under § 60.7(b) through (f). A ''major change to recordkeeping/reporting'' is defined in 40 CFR 63.90.

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