Federal Register

Monday,
May 14, 2007

Part II

Environmental Protection Agency

40 CFR Part 60

Standards of Performance for Petroleum Refineries; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2007–0011; FRL–8309–1]

RIN 2060–AN72

Standards of Performance for Petroleum Refineries

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rules.

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

DATES: *Comments.* Written comments must be received on or before July 13, 2007.

Public Hearing. If anyone contacts EPA by June 4, 2007 requesting to speak at a public hearing, a public hearing will be held on June 13, 2007.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2007–0011, by one of the following methods:

- *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail: a-and-r-docket@epa.gov.*
- *Fax:* (202) 566–1741.
- *Mail: U.S. Postal Service, send comments to:* EPA Docket Center (6102T), New Source Performance Standards for Petroleum Refineries Docket, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), *Attn:* Desk Officer for EPA, 725 17th St., NW., Washington, DC 20503.
- *Hand Delivery: In person or by courier, deliver comments to:* EPA Docket Center (6102T), New Source Performance Standards for Petroleum Refineries Docket, EPA West, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information. Please include a total of two copies.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2007–0011. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* website is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov*, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, Standards of Performance for Petroleum Refineries Docket, EPA West, 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 Docket Center 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 this proposed rule 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 Industrial 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. What should I consider as I prepare my comments to EPA?

Do not submit information containing CBI to EPA through *http://www.regulations.gov* or e-mail. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, NC 27711, Attention Docket ID No. EPA–HQ–OAR–2007–0011. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

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

In addition to being available in the docket, an electronic copy of this proposed action is available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of this proposed 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.

D. When would a public hearing occur?

If anyone contacts EPA requesting to speak at a public hearing by June 4, 2007, a public hearing will be held on June 13, 2007. Persons interested in presenting oral testimony or inquiring as to whether a public hearing is to be held should contact Mr. Bob Lucas, listed in the **FOR FURTHER INFORMATION CONTACT** section, at least 2 days in advance of the hearing.

E. How is this document organized?

The supplementary information presented in this preamble is organized as follows:

I. General Information
A. Does this action apply to me?
B. What should I consider as I prepare my comments to EPA?
C. Where can I get a copy of this document?
D. When would a public hearing occur?
E. How is this document organized?
II. Background Information
A. What is the statutory authority for the proposed standards and proposed amendments?
B. What are the current petroleum refinery NSPS?
III. Summary of the Proposed Standards and Proposed Amendments
A. What are the proposed amendments to the standards for petroleum refineries (40 CFR part 60, subpart J)?
B. What are the proposed requirements for new fluid catalytic cracking units and new fluid coking units (40 CFR part 60, subpart Ja)?
C. What are the proposed requirements for new sulfur recovery plants (SRP) (40 CFR part 60, subpart Ja)?
D. What are the proposed requirements for new process heaters and other fuel gas combustion devices (40 CFR part 60, subpart Ja)?
E. What are the proposed work practice and equipment standards (40 CFR part 60, subpart Ja)?
IV. Rationale for the Proposed Amendments (40 CFR part 60, subpart J)
A. How is EPA proposing to change requirements for refinery fuel gas?
B. How is EPA proposing to amend definitions?
C. How is EPA proposing to revise the coke burn-off equation?
D. What miscellaneous corrections are being proposed?
V. Rationale for the Proposed Standards (40 CFR part 60, subpart Ja)
A. What is the performance of control technologies for fluid catalytic cracking units?
B. What is the performance of control technologies for fuel gas combustion?
C. What is the performance of control technologies for process heaters?
D. What is the performance of control technologies for sulfur recovery systems?
E. How did EPA determine the proposed standards for new petroleum refining process units?
VI. Modification and Reconstruction Provisions
VII. Request for Comments
VIII. Summary of Cost, Environmental, Energy, and Economic Impacts
A. What are the impacts for petroleum refineries?
B. What are the secondary impacts?
C. What are the economic impacts?
D. What are the benefits?
IX. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
D. Unfunded Mandates Reform Act
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

II. Background Information

A. What is the statutory authority for the proposed standards and proposed amendments?

New source performance standards (NSPS) implement Clean Air Act (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.

B. What are the current petroleum refinery NSPS?

NSPS for petroleum refiners (40 CFR part 60, subpart J) apply to fluid catalytic cracking unit catalyst regenerators and fuel gas combustion devices that commence construction or modification after June 11, 1973. Fluid catalytic cracking unit catalyst regenerators are subject to standards for particulate matter (PM), opacity, and carbon monoxide (CO). Fluid catalytic cracking unit catalyst regenerators that commence construction after January 17, 1984 are also subject to standards for sulfur dioxide (SO_2) (or a feed sulfur content limit). Fuel gas combustion devices are subject to concentration limits for hydrogen sulfide (H_2S) as a surrogate for SO_2 emissions.

The current NSPS also apply to all Claus sulfur recovery plants (SRP) of more than 20 long tons per day (LTD) that commence construction or modification after October 4, 1976. Claus SRP are subject to standards for either SO_2 or both reduced sulfur compounds and H_2S.

The NSPS were originally promulgated on March 8, 1974 and have been amended several times. Significant changes to emission limits since the original promulgation date include the addition of the sulfur oxide standards for SRP and fluid catalytic cracking units (see 43 FR 10869, March 15, 1978 and 54 FR 34027, August 17 1989).

III. Summary of the Proposed Standards and Proposed Amendments

We are proposing 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 proposed standards in 40 CFR part 60, subpart Ja. For example, we are proposing language to change 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 and are exempt from 40 CFR 60.104(a)(1). These gas streams are not required to be monitored. In a related amendment, we are proposing to clarify that monitoring is not required for fuel gases that are identified as inherently low sulfur or can demonstrate a low sulfur content. 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 proposed standards in 40 CFR part 60, subpart Ja include emission limits for fluid catalytic cracking units, fluid coking units, SRP, and fuel gas combustion devices. They also include work practice standards for minimizing the quantity of fuel gas streams flared from all refinery process units and for minimizing the SO_2 emissions from process units that are subject to standards of performance for SO_2 emissions. Proposed equipment standards would reduce emissions of volatile organic compounds (VOC) from delayed coker units. Only those affected facilities that begin construction, modification, or reconstruction after May 14, 2007 would be affected by the proposed standards in 40 CFR part 60, subpart Ja. Units for which construction, modification, or reconstruction began on or before May 14, 2007 would continue to comply with the applicable standards under the current NSPS in 40 CFR part 60, subpart J, as amended.

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

We are proposing to amend the definition of ''fuel gas'' to exempt 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 would still be considered affected fuel gas combustion devices, and all auxiliary fuel fired to these devices would be subject to the fuel gas limit; however, continuous monitoring would not be required for the collected vapors that are being incinerated because these gases would not be considered fuel gases under the proposed definition of ''fuel gas'' in subpart J.

We are also proposing to exempt certain fuel gas streams from all continuous monitoring requirements. Monitoring is currently not required for events that are exempt from the requirements in 40 CFR 60.104(a)(1) (flaring of process upset gases or flaring of gases from relief valve leakage or emergency malfunctions). Additionally, monitoring would not be required for inherently low sulfur fuel gas streams. These streams include pilot gas flames, gas streams that meet commercial-grade product specifications with a sulfur content 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 would be required to document the exemption for which each fuel gas stream applies and ensure that the stream remains qualified for that exemption.

We are proposing to amend the definitions of ''Claus sulfur recovery plant,'' ''oxidation control system,'' and ''reduction control system'' to clarify that a SRP may consist of multiple units, that sulfur pits are part of the Claus SRP, and that the oxidized or reduced sulfur is recycled to the beginning of a sulfur recovery train within the SRP. We are also proposing to add a fourth term to the coke burn-off rate equation to account for the use of O_2-enriched air.

Finally, the proposed amendments include a few technical corrections to fix references and other miscellaneous errors in subpart J. The specific changes are detailed in section IV.D of this preamble.

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

The proposed standards for new fluid catalytic cracking units include emission limits for PM, SO_2, nitrogen oxides (NO_X), and CO. One difference from the existing standards in subpart J is that new fluid coking units would be subject to the same standards as fluid catalytic cracking units. Other differences from the existing standards are that the proposed PM and SO_2 emission limits are more stringent and the NO_X emission limit is a new requirement. Unlike the existing standards, the proposed standards include no opacity limit because the opacity limit was intended to ensure compliance with the PM limit and because we are now proposing that sources use direct PM monitoring or parameter monitoring to ensure compliance with the PM limit.

The proposed PM emission limit for new fluid catalytic cracking units and new fluid coking units is 0.5 kilogram (kg) per Megagram (kg/Mg) (0.5 pound (lb)/1,000 lb) of coke burn-off in the regenerator. Initial compliance with this emission limit would be determined using Method 5 in Appendix A to 40 CFR part 60. Procedures for computing the PM emission rate using the total PM concentration, effluent gas flow rate, and coke burn-off rate would be the same as in 40 CFR part 60, subpart J, as amended. To demonstrate ongoing compliance, an owner or operator must either monitor PM emission control device operating parameters or use a PM continuous emission monitoring system (CEMS). If operating parameters will be 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 lowest hourly average values for the applicable parameters measured over the three test runs. The owner or operator must also conduct additional performance tests at least once every 24 months to verify compliance with the PM emission limit and confirm or reestablish operating limits. If ongoing compliance will be demonstrated using a PM CEMS, the CEMS must meet the conditions in Performance Specification 11. Thus, separate performance tests are not required because the equivalent of an initial performance test will be part of the initial correlation test for the PM CEMS, and periodic response correlation audits (every 5 years) will

include the equivalent of performance tests. We are co-proposing requiring reconstructed and modified fluid catalytic cracking units to meet the current standards in 40 CFR part 60, subpart J, and we are requesting comments on the effects of the proposed PM standard on modified or reconstructed facilities and if it is appropriate to adopt a different standard for these sources.

The proposed SO_2 emission limits for new fluid catalytic cracking units and new fluid coking units 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 proposed 50 ppmv SO_2 emission limit would be demonstrated by conducting a performance evaluation of the SO_2 CEMS in accordance with Performance Specification 2 in appendix B of 40 CFR part 60, with Method 6, 6A, or 6C of 40 CFR part 60, appendix A as the reference method. Ongoing compliance with both proposed SO_2 emission limits would be determined using the CEMS to measure SO_2 emissions as discharged to the atmosphere, averaged over the 7-day and 365-day averaging periods. Rolling average concentrations would be calculated once per day using the applicable number of daily average values. We are co-proposing requiring reconstructed and modified fluid catalytic cracking units to meet the current standards in 40 CFR part 60, subpart J, and we are requesting comments on the effects of the proposed SO_2 standard on modified or reconstructed facilities.

The proposed NO_X emission limits for new fluid catalytic cracking units and new fluid coking units are 80 ppmv on a 7-day rolling average basis (dry at 0 percent excess air). Initial compliance with the 80 ppmv emission limit would be demonstrated by conducting a performance evaluation of the CEMS in accordance with Performance Specification 2 in appendix B to 40 CFR part 60, with Method 7 of 40 CFR part 60, subpart A as the Reference Method. Ongoing compliance with this emission limit would be determined using the CEMS to measure NO_X emissions as discharged to the atmosphere, averaged over 7-day periods. We are also co-proposing no new standards for NO_X emissions from fluid coking units and for modified or reconstructed fluid catalytic cracking units.

The proposed CO emission limit for new fluid catalytic cracking units and new fluid coking units is 500 ppmv (1-hour average, dry at 0 percent excess air). Initial compliance with this emission limit would be demonstrated by conducting a performance evaluation for the CEMS in accordance with Performance Specification 4 in appendix B to 40 CFR part 60, with Method 10 or 10A in 40 CFR part 60, appendix A as the Reference Method. For Method 10, the integrated sampling technique is to be used. Ongoing compliance with this emission limit would be determined on an hourly basis using the CEMS to measure CO emissions as discharged to the atmosphere. An exemption from monitoring may be requested if the owner or operator can demonstrate that average CO emissions are less than 50 ppmv (dry basis). This limit and the compliance procedures are the same as in the existing NSPS for fluid catalytic cracking units.

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

The proposed standards include SO_2 emission limits for all SRP. The proposed emission limit for new SRP greater than 20 LTD is 250 ppmv or less of combined SO_2 and reduced sulfur compounds as discharged to the atmosphere (reported as SO_2 on a dry basis at 0 percent excess air). For a SRP with a capacity of 20 LTD or less, the proposed standard is mass emissions of combined SO_2 and reduced sulfur compounds equal to 1 weight percent or less of sulfur recovered. In addition, the proposed standards include an H_2S concentration limit of 10 ppmv or less (dry basis at 0 percent excess air) for all new SRP. Both SO_2 and H_2S concentration limits would be determined hourly on a 12-hour rolling average basis. As in the amendments to subpart J, the proposed definition of a SRP would include the sulfur pit.

Initial compliance with the emission limit for combined SO_2 and reduced sulfur compounds is demonstrated by conducting a performance evaluation for the SO_2 CEMS in accordance with Performance Specification 2 in appendix B to 40 CFR part 60, with Method 6, 6A, or 6C in 40 CFR part 60, appendix A as the Reference Method to determine the SO_2 concentration, and Method 15 in 40 CFR part 60, appendix A as the Reference Method to determine the SO_2-equivalent concentration of the reduced sulfur compounds. The results of the test using Method 15 are also used to demonstrate initial compliance with the H_2S concentration limit. Initial compliance with the mass sulfur emission limit is demonstrated by conducting a performance test as described above to determine the combined SO_2 and SO_2-equivalent concentration, and then converting that concentration to a mass fraction using the volumetric flow rate of effluent gas and the mass rate of sulfur recovery during the performance test.

Ongoing compliance with the combined SO_2 and reduced sulfur compounds emission limit would be determined using 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. An O_2 monitor would also be required for converting the measured combined SO_2 concentration to the concentration at 0 percent O_2. Ongoing compliance with the mass sulfur emission limit would be determined using the same types of CEMS. A flow monitor that continuously monitors the volumetric flow rate of gases released to the atmosphere would be required so that the mass emitted can be calculated. The hourly sulfur production rates would also have to be tracked so that mass fraction emitted can be calculated and compared with the proposed 1 percent emission limit.

Ongoing compliance with the H_2S concentration limit would be determined using either an H_2S CEMS or, if the SRP is equipped with an oxidation control system or followed by incineration, by continuous monitoring of the operating temperature and O_2 concentration. Minimum operating limits for the operating temperature and O_2 concentration would be established during the performance test.

D. What are the proposed requirements for new process heaters and other fuel gas combustion devices (40 CFR part 60, subpart Ja)?

The proposed standards for new process heaters include both SO_2 and NO_X emission limits. Because of this, the fuel gas combustion units as defined in the existing subpart J standards were divided into two separate affected sources: ''process heaters'' and ''other fuel gas combustion devices.'' The primary sulfur oxides emission limit for new process heaters and other fuel gas combustion devices is 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. For process heaters that use only fuel gas and other fuel gas combustion devices, we are proposing an alternative concentration limit of 160 ppmv or less H_2S or total reduced sulfur (TRS) in the fuel gas on a 3-hour rolling average basis (as in the existing NSPS) and 60 ppmv or less H_2S or TRS in the fuel gas on a

365-day rolling averaging basis. The TRS concentration limit is required for new fuel gas combustion devices that combust fuel gas generated from coking units (as either the only fuel or as a mixture of fuel gases from other units). On the other hand, new fuel gas combustion devices that do not combust fuel gas generated from coking units are required to monitor H_2S concentrations. Compliance would be demonstrated either by measuring H_2S (or TRS) in the fuel gas or by measuring SO_2 in the exhaust gas.

Initial compliance with the 20 ppmv SO_2 limit or the 160 ppmv H_2S or TRS concentration limits would be demonstrated by conducting a performance evaluation for the CEMS. The performance evaluation for an SO_2 CEMS would be conducted in accordance with Performance Specification 2 in appendix B to 40 CFR part 60, with Method 6, 6A, or 6C as the Reference Method. The performance evaluation for an H_2S CEMS would be conducted in accordance with Performance Specification 7 in 40 CFR part 60, with Method 11, 15, 15A, or 16 as the Reference Method. The performance evaluation for a TRS CEMS would be conducted in accordance with Performance Specification 7 in 40 CFR part 60, with Method 16 as the Reference Method. Ongoing compliance with the proposed sulfur oxides emission limits would be determined using the applicable CEMS to measure either H_2S or TRS in the fuel gas being used for combustion or SO_2 in the exhaust gas to the atmosphere, averaged over the 3-hour and 365-day averaging periods.

Similar to proposed clarifications for 40 CFR part 60, subpart J, we are proposing a definition of ''fuel gas'' that includes exemptions for vapors collected and combusted in an air pollution control device installed to comply with specified wastewater or marine vessel loading provisions. Also similar to subpart J, we are proposing to exempt from continuous monitoring fuel gas streams exempt under 40 CFR 60.102a(i) and fuel gas streams that are inherently low in sulfur. We are also proposing to streamline the process for an owner or operator to demonstrate that a fuel gas stream not explicitly exempted from continuous monitoring is inherently low sulfur.

The proposed NO_X emission limits for new process heaters is 80 ppmv on a 7-day rolling average basis (dry at 0 percent excess air). Initial compliance with the 80 ppmv emission limit would be demonstrated by conducting a performance evaluation of the CEMS in accordance with Performance Specification 2 in appendix B to 40 CFR part 60, with Method 7 of 40 CFR part 60, subpart A as the Reference Method. Ongoing compliance with this emission limit would be determined using the CEMS to measure NO_X emissions as discharged to the atmosphere, averaged over 7-day periods.

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

Three work practice standards are proposed to reduce both VOC and SO_2 emissions from flares, start-up/shutdown/malfunction events, and delayed coker units. First, the proposed rule requires all new fuel gas producing units at a refinery to be designed and operated in such a way that the fuel gas produced by the new process units does not routinely discharge to a flare. Second, a requirement for a start-up, shutdown and malfunction plan that includes procedures to minimize discharges either directly to the atmosphere or to the flare gas system during the planned startup or shutdown of these units, procedures to minimize emissions during malfunctions of the amine treatment system or sulfur recovery plant, and procedures for conducting a root-cause analysis of an emissions limit exceedance or process start-up, shutdown, upset, or malfunction that causes a discharge into the atmosphere, either directly or indirectly, from any refinery process unit subject to the provisions of this subpart in excess of 500 lb per day (lb/d) of SO_2. Third, the proposed rule would require delayed coking units to depressure to 5 lbs per square inch gauge (psig) during reactor vessel depressuring and vent the exhaust gases to the fuel gas system. For new, reconstructed, or modified units, we are co-proposing to require only the last of these work practice standards, the requirement to depressure coking units to the flare.

IV. Rationale for the Proposed Amendments (40 CFR part 60, subpart J)

Because we are proposing a new subpart to 40 CFR part 60 for affected sources at petroleum refineries beginning construction, reconstruction, or modification after May 14, 2007, our proposed amendments to subpart J of 40 CFR part 60 would impact only those affected sources that are already subject to 40 CFR part 60, subpart J. The proposed amendments to this subpart include clarifications of the current requirements and technical corrections to the regulatory language. These changes to subpart J of 40 CFR part 60 are discussed below.

A. How is EPA proposing to change requirements for refinery fuel gas?

As we conducted our review of 40 CFR part 60, subpart J, we found that the definition of ''fuel gas'' has been broadly interpreted by States and EPA Regions over the last 30 years. Because of the increasing complexity of petroleum refineries, this interpretation may be more inclusive than originally intended in the 1970s. We agree that the interpretation ensures that all streams that could be considered fuel gas and have the potential for high-sulfur emissions are included in the regulatory requirements, but we recognize that this broad definition has resulted in application of the fuel gas concentration limits to fuel gas streams and combustion devices that were not originally considered in the standards development process. Furthermore, had these extended applications been considered in the standards development process, some of the applications would have been found to be either technically or economically infeasible. The existing requirements in subpart J of 40 CFR part 60 do recognize and limit the applicability of the fuel gas concentration limits to certain gas streams. For example, 40 CFR 60.101(d) excludes gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners from the definition of ''fuel gas.'' These gases were excluded because the sulfur in the gases generated by the catalytic cracking unit catalyst regenerators and fluid coking burners is in the form of sulfur oxides rather than H_2S. As such, these gases are not amenable to amine treatment, which was the primary treatment technique on which the fuel gas concentration limits were based. In addition, 40 CFR 60.104(a)(1) exempts process upset gases or fuel gas released to the flare as a result of relief valve leakage or emergency malfunctions from the fuel gas H_2S concentration limits. In this case, it was determined that requiring treatment of these gases was either technically or economically infeasible. Therefore, it is entirely in keeping with the regulatory intent of the NSPS and the specific requirements in 40 CFR part 60, subpart J to exclude or exempt sources based on technical and economic considerations.

Since the development of the refinery fuel gas concentration limits in the early 1970s, EPA has developed numerous other standards in which incineration was promoted as a best air pollution management practice for certain organic vapors which had traditionally been

released directly to the atmosphere. These gas streams were never considered in the development of the 40 CFR part 60, subpart J standards because they were not directed to a fuel gas combustion device at the time. As such, the technical and economical feasibility of meeting the fuel gas concentration limits was not specifically evaluated for these gas streams at that time. During our review, we evaluated the application of the fuel gas concentration limits to a variety of process gas streams that did not exist in the early 1970s. We concluded that most of these gas streams are amenable to amine treatment and that it is both technically and economically feasible to treat those gas streams to meet the fuel gas concentration limits. However, we identified a few specific streams that are not readily amenable to amine treatment (or direct diversion to the SRP) and/or are not cost-effective to amine treatment due to the typically low (but potentially variable) H_2S content and the typical location of these gas streams in relationship to the primary processing units at the refinery.

As a result of this evaluation, we are proposing to change the requirements of the fuel gas concentration limits in keeping with a broad definition of fuel gas, but recognizing the technical and economic issues related to certain fuel gas streams or combustion devices. Specifically, we are proposing to exempt from the definition of ''fuel gas'' vapors that are collected and combusted in an air pollution control device installed to comply with the Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems (40 CFR part 60, subpart QQQ), National Emission Standards for Benzene Waste Operations (40 CFR part 61, subpart FF), the National Emission Standards for Marine Tank Vessel Loading Operations (40 CFR part 63, subpart Y), or the National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries (40 CFR part 63, subpart CC), specifically either 40 CFR 63.647 or 40 CFR 63.651. The wastewater and marine vessel loading sources subject to these specific regulations are often located at the edge of the refinery property, if not off-site, and compliance with the regulations is generally demonstrated by capturing and combusting the organic vapors. The collected gases generally have low sulfur content, but variability in the products being loaded and in wastewater treatment process operations may result in the collected gases exceeding the current fuel gas concentration limits for short periods of time. Due to the typical low sulfur content of these gases, they are not generally suitable for amine treatment; due to the presence of O_2 in these collected gases, they cannot be routed to the fuel gas system. Furthermore, these sources are typically far from amine treatment or the SRP, and it is not economically reasonable to propose control beyond the existing regulations for these sources (e.g., requiring these streams to be routed to sulfur treatment rather than being combusted). Therefore, we are proposing to amend the definition of ''fuel gas'' in 40 CFR 60.101(d) to exclude from the fuel gas concentration limits the vapors collected and combusted in air pollution control devices to comply with the specified regulations in 40 CFR part 60, subpart QQQ, 40 CFR part 61, subpart FF, or 40 CFR part 63, subparts Y or CC. The thermal combustion control devices would still be considered affected fuel gas combustion devices and all auxiliary fuel fired to these devices would be subject to the fuel gas concentration limit; however, continuous monitoring would not be required for the collected vapors that are being incinerated because these gases would not be considered fuel gases under the proposed definition of ''fuel gas'' in subpart J.

We are also proposing to clarify that monitoring is not required for fuel gas streams that are exempt from the requirements in 40 CFR 60.104(a)(1). These streams include process upset gases or fuel gases that are released to the flare as a result of relief valve leakage or other emergency malfunctions. To clarify this point, the proposed introductory text for 40 CFR 60.105(a)(4)(iv) specifies that continuous monitoring is not required for streams that are exempt from 40 CFR 60.104(a)(1). We are also proposing to add the phrase ''for fuel gas combustion devices subject to 40 CFR 60.104(a)(1)'' after ''Instead of the SO_2 monitor in paragraph (a)(3) of this section'' in 40 CFR 60.105(a)(4). This proposed amendment is more consistent with the language in 40 CFR 60.105(a)(3). Given our intent not to require fuel gas monitoring of process upset gases, combustion devices such as emergency flares would likely not require monitoring unless sources other than process upset gases are burned, such as routine vents or sweep gas. We are aware of issues related to the identification and exemption of these units from fuel gas monitoring. We are requesting comment on the need to provide specific language exempting these units, and on appropriate methods for identifying emergency flares and verifying on an ongoing basis that no flaring of nonexempt gases is occurring.

In addition to the exemptions described in the previous paragraphs, we are proposing to exempt certain fuel gas streams from all monitoring requirements. These streams would still be subject to the fuel gas concentration limits, but since we do not expect that these streams would exceed this limit (except in the case of a process upset or malfunction, in which case the fuel gases would be exempt from meeting the limit), continuous monitoring of these streams is unnecessary. We have divided these streams into four overall categories, as specified in proposed 40 CFR 60.105(a)(4)(iv)(A) through (D). The first category includes pilot gas flames, which are fairly insignificant sources. Although previous determinations effectively excluded these gases from the requirements of the rule, we believe it is good air pollution control practice to fire pilot lights with natural gas or treated fuel gas. However, even when considering the pilot flame as part of the fuel gas combustion device, the potential for sulfur oxide emissions from these sources is insignificant and it is not cost-effective to require continuous monitoring of these gas streams. Therefore, we are changing in the monitoring requirements that monitoring of pilot flame fuel gas is not required.

The second category includes gas streams that meet commercial-grade product specifications with a sulfur content of 30 ppmv or less. Placing a limit on the sulfur content of the products that we are proposing to exempt from monitoring ensures that only low-sulfur products are excluded. The 30 ppmv limit for commercial-grade gas products was selected because it provides a sufficient margin of safety to ensure continuous compliance with the proposed annual average H_2S concentration limit of 60 ppmv regardless of normal fluctuations in the composition of commercial grade products.

We are requesting comment on the appropriateness of an additional exemption for gas streams that were generated from certain commercial-grade liquid products (e.g., displaced vapors from a storage tank or loading rack for gasoline or diesel fuel). The most straightforward approach would be to exempt gas streams associated with commercial liquid products that contain sulfur below some specified weight percent level. For example, we expect that most of the sulfur-containing compounds in gasoline meeting the Tier 2 sulfur standards or in diesel fuel

meeting the low-sulfur diesel fuel standards have high molecular weights and low vapor pressures such that gas streams in equilibrium with them would have sulfur contents below the proposed 30 ppmv level. To confirm this assumption, we are asking for data on the typical concentrations and vapor pressures of the most prevalent mercaptans, thiophenes, and other sulfur-containing compounds in these or other commercial liquid products.

We would use these data to calculate the corresponding vapor phase concentrations of gas streams in equilibrium with the liquid products using Raoult's Law. Given the extremely low concentrations of the sulfur-containing compounds in the liquid products, we are also seeking comment on whether Raoult's Law gives a realistic estimate of their vapor phase partial pressures. We are also interested in any test data to support this approach, and we are interested in any other approaches to develop an exemption for gas streams associated with commercial-grade liquid products.

The third category includes fuel gases produced by process units that are intolerant of sulfur contamination. There are a few process units within a refinery whose operation is dependent on keeping the sulfur content low. If there is too much sulfur in the gas streams entering these units, the process units could malfunction. Specifically, the methane reforming unit in the hydrogen plant, the catalytic reforming unit, and the isomerization unit are intolerant of sulfur in the process streams; therefore, these streams are treated to remove sulfur prior to processing in these units. Fuel gases subsequently formed in these process units are low in sulfur because the process feedstocks are necessarily low in sulfur. As such, we find that requiring continuous monitoring of the H_2S content in these gas streams or requiring each individual refinery to develop and implement an alternative monitoring plan (AMP) is unnecessary and creates needless obstacles to using the produced fuel gas directly in the heaters associated with these process units. We are asking for comment on whether fuel gas is generated from any other process units that are intolerant of sulfur. Comments recommending the exemption of fuel gas streams from other units should identify the problems sulfur cause in the unit, procedures used to reduce sulfur in the gas stream before it is processed in the unit, and the expected sulfur content of the outlet fuel gas stream.

For all of the above low-sulfur streams that an owner or operator determines are exempt from all monitoring requirements, the owner or operator must document which of the exemptions applies to each stream. If the refinery operations associated with an exempt stream change, the owner or operator must document the change and determine whether the stream continues to be exempt. If the refinery operations or the composition of an exempt stream change in such a way that the stream is no longer exempt from monitoring, the owner or operator must begin continuous monitoring within 15 days after the change occurs.

In addition, we are proposing a standardized, streamlined procedure to exempt from continuous monitoring streams that an owner or operator can demonstrate are inherently low-sulfur (i.e., consistently 5 ppmv or less H_2S) following the procedures specified in proposed 40 CFR 60.105(b). The information that an owner or operator must provide to EPA is similar to the information and items needed to apply for an AMP, as described in the EPA document ''Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas.'' In general, once an AMP is approved for an affected source, the owner or operator must continue to monitor the stream, although a methodology other than a continuous monitor may be used. For this specific exemption, however, once an application to demonstrate that a stream is inherently low-sulfur is approved by EPA, that stream is exempt from monitoring until there is a change in the refinery operation that affects the stream or the stream composition changes. If the sulfur content of the stream changes but is still within the range of concentrations included in the original application, the owner or operator will conduct H_2S testing on a grab sample as proof and record the results of the test. If the sulfur content of the stream changes such that the sulfur concentration is outside the range provided in the original application, the owner or operator must submit a new application that must be approved in order for the stream to continue to be exempt from continuous monitoring. If a new application is not submitted, the owner or operator must begin continuous monitoring within 15 days.

B. How is EPA proposing to amend definitions?

We are proposing to amend the definition of ''Claus sulfur recovery plant'' in 40 CFR 60.101(i). These changes would clarify that the SRP may consist of multiple units, and the types of units that are part of a SRP would be listed within the definition. Note that sulfur pits would be included as one of the units, which is consistent with the Agency's current interpretation of the existing definition.

In conjunction with this amendment, we are also proposing to amend the definitions of ''oxidation control system'' and ''reduction control system'' in 40 CFR 60.101(j) and 40 CFR 60.101(k), respectively. The amended definitions would specify that the oxidized or reduced sulfur is recycled to the beginning of a sulfur recovery train within the SRP and are consistent with the proposed definitions in 40 CFR 60.101a of subpart Ja. This clarification would ensure that thermal oxidizers that convert the sulfur to SO_2 but do not recycle and recover the oxidized sulfur are not considered oxidation control systems.

C. How is EPA proposing to revise the coke burn-off equation?

The current equation for calculating coke burn-off rate in 40 CFR 60.106(b)(3) assumes that each fluid catalytic cracking unit is using air with 21 percent O_2. However, there are some fluid catalytic cracking units that use O_2-enriched air, and for these units, the current equation is not completely accurate. Equation 1 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) includes an additional term to account for the use of an O_2-enriched air stream. For accuracy in the calculation of the coke burn-off rate, we are proposing to revise 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). This revision also includes changing 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).

D. What miscellaneous corrections are being proposed?

See Table 1 of this preamble for the miscellaneous technical corrections not previously described in this preamble that we are proposing throughout 40 CFR part 60, subpart J.

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

Section	Proposed technical correction and reason
60.100	Replace instances of ''construction or modification'' with ''construction, reconstruction, or modification.''
60.100(b)	Replace ''except Claus plants of 20 long tons per day (LTD) or less'' with ''except Claus plants with a design capacity 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; sources beginning construction, reconstruction, or modification after this date will be subject to 40 CFR part 60, subpart Ja.
60.101	Rearrange definitions alphabetically for ease in locating a specific definition.
60.102(b)	Replace ''g/MJ'' with ''grams per Gigajoule (g/GJ)'' to correct units.
60.104(b)(1)	Replace ''50 ppm by volume (vppm)'' with ''50 ppm by volume (ppmv)'' for consistency in unit 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.
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 SO_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 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.
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).
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).
60.109(b)(2)	Add a reference to 40 CFR 60.106(e)(3) to specify that determining whether a fuel gas stream is low-sulfur may not be delegated to States.
60.109(b)(3)	Redesignate current 40 CFR 60.109(b)(2) as 40 CFR 60.109(b)(3) to allow space for a new paragraph (b)(2).

V. Rationale for the Proposed Standards (40 CFR part 60, subpart Ja)

A. What is the performance of control technologies for fluid catalytic cracking units?

1. PM Control Technologies

Filterable PM emissions from fluid catalytic cracking units are predominately fine catalyst particles generated from the mechanical grinding of catalyst particles as the catalyst is continuously recirculated between the fluid catalytic cracking unit and the catalyst regenerator. Control of PM emissions from fluid catalytic cracking units relies on the use of post-combustion controls to remove solid particles from the flue gases. Electrostatic precipitators (ESP) and wet scrubbers are the predominant technologies used to control PM from fluid catalytic cracking units. Either of these PM control technologies can be designed to achieve overall PM collection efficiencies in excess of 95 percent.

Electrostatic Precipitator (ESP). An ESP operates by imparting an electrical charge to incoming particles, and then attracting the particles to oppositely charged metal plates for collection. Periodically, the particles collected on the plates are dislodged in sheets or agglomerates (by rapping the plates) and fall into a collection hopper. The normal PM control efficiency range for an ESP is between 90 and 99+ percent. One of the major advantages of an ESP is that it operates with essentially little pressure drop in the gas stream. They are also capable of handling high temperature conditions.

Wet Scrubbers. Wet scrubbers use a water spray to coat and agglomerate particles entrained in the flue gas. To improve wetting of fine particulates, either enhanced spray nozzles or venturi acceleration is used. The wetted particles are then removed from the flue gas through centrifugal separation. Wet scrubbers have similar collection efficiencies as dry ESP (90 to 98 percent), but they are also effective in removing SO_2 emissions. Wet scrubbers may also be more effective in controlling condensable PM as they often use water quench and thereby operate at lower temperatures than ESP used to control fluid catalytic cracking units. Wet scrubbers are generally more costly to operate than ESP due to higher pressure drops across the control device and because of water treatment and disposal costs. However, they become economically viable if significant SO_2 emissions reductions are also needed.

Fabric Filters. A fabric filter collects PM in the flue gases by passing the gases through a porous fabric material. The buildup of solid particles on the fabric surface forms a thin, porous layer of solids, which further acts as a filtration medium. Gases pass through this cake/fabric filter, and all but the finest-sized particles are trapped on the cake surface. Collection efficiencies of fabric filters can be as high as 99.99 percent. Fabric filters tend to be more efficient for fine particles (those less than 2.5 microns in diameter) than ESP or wet scrubbers.

The primary concern with fabric filters are maintenance requirements of the baghouses given the long run times of typical fluid catalytic cracking units. Small process upsets (e.g., pressure changes) in the fluid catalytic cracking unit and regenerator system can send high concentrations of particles to the control system. These particles would likely blind the filter bags, causing a shut-down of the unit to replace the filter bags. Wet scrubbers and ESP can more easily accommodate and control high concentrations of particles.

2. SO_2 Control Technologies

During combustion, sulfur compounds present in the deposited coke are predominately oxidized to gaseous SO_2. One approach to controlling SO_2 emissions from catalytic cracking units is to limit the maximum sulfur content in the feedstock to the

catalytic cracking unit. This can be accomplished by processing crude oil that naturally contains low amounts of sulfur or a feedstock that has been pre-treated to remove sulfur (i.e., hydrotreatment or hydrodesulfurization). A second approach is to use a post-combustion control technology that removes SO_2 from the flue gases. These technologies rely on either absorption or adsorption processes that react SO_2 with lime, limestone, or another alkaline material to form an aqueous or solid sulfur by-product. A third approach is the use of catalyst additives, which capture sulfur oxides in the regenerator and return them to the fluid catalytic cracking reactor where they are transformed to H_2S that is ultimately exhausted to the SRP.

Feedstock Selection or Pre-Treatment. The SO_2 emissions from the fluid catalytic cracking unit are directly related to the amount of sulfur deposited on the catalyst particles in the riser and reactor section of the unit. The amount of sulfur deposited on the catalyst is a function of both the amount of sulfur in the feedstocks and the relative composition of the sulfur-containing compounds in the feedstocks (mercaptans, thiosulfates). As the concentration of sulfur in the feedstocks is reduced, the SO_2 emissions from the regenerator portion of the unit are also reduced. Therefore, if a refinery processes ''sweet'' crude (oil naturally low in sulfur) or if a refinery removes sulfur from the feedstocks of the fluid catalytic cracking unit, the SO_2 emissions from the catalyst regenerator will be lower than from refineries that process feedstocks that have higher sulfur content. At a petroleum refinery, the primary means of removing sulfur compounds in the liquid feedstocks is catalytic hydrotreatment. Hydrotreatment typically reduces the sulfur content in process streams to between 20 and 1,000 parts per million by weight.

Alkali Wet Scrubbing. The SO_2 in a flue gas can be removed by reacting the sulfur compounds with a solution of water and an alkaline chemical to form insoluble salts that are removed in the scrubber effluent. Wet scrubbing processes used to control SO_2 are generally termed flue-gas desulfurization (FGD) processes. The normal SO_2 control efficiency range for SO_2 scrubbers is 80 percent to 90 percent for low efficiency scrubbers and 90 percent to 99 percent for high efficiency scrubbers. In recent fluid catalytic cracking unit applications, control guarantees of 25 ppmv SO_2 are commonly provided by FGD suppliers.

Spray Dryer Adsorption. An alternative to using wet scrubbers is to use spray dryer adsorber (SDA) technology. A SDA operates by the same principle as alkali wet scrubbing, except that instead of a bulk liquid (as in wet scrubbing) the flue gas containing SO_2 is contacted with fine spray droplets of hydrated lime slurry in a spray dryer vessel. This vessel is located downstream of the air heater outlet where the gas temperatures are in the range of 120 °C to 180 °C (250 °F to 350 °F). The SO_2 is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate. The water is evaporated by the hot flue gases and forms dry, solid particles containing the reacted sulfur. Most of the SO_2 removal occurs in the spray dryer vessel itself, although some additional SO_2 capture has also been observed in downstream particulate collection devices. The SO_2 removal efficiencies of new lime spray dryer systems are generally greater than 90 percent. Only one refinery has ever used an SDA to control SO_2 from its fluid catalytic cracking unit; this system has since been removed in favor of feedstock hydrotreatment.

Catalyst Additives. One common method used by refineries to reduce SO_2 emissions from the fluid catalytic cracking unit is the use of catalyst additives (typically various types of metal oxides). The metal oxide reacts with some of the SO_3 in the catalyst regenerator to form a metal sulfate. The metal sulfate is then returned to the cracking unit where the sulfur is converted to a metal sulfide and then to H_2S and the original metal oxide. The H_2S is subsequently recovered in the SRP, and the metal oxide returns to the catalyst regenerator to repeat the process. The control efficiency of catalyst additives is difficult to assess, but is generally around 50 percent (ranging from 20 to 70 percent, depending on the application).

3. NO_X Control Technologies

NO_X are formed in a catalyst regenerator (and downstream CO boiler, if present) by the oxidation of molecular nitrogen (N_2) in the combustion air and any nitrogen compounds contained in the fuel (*i.e.*, thermal NO_X and fuel NO_X). The formation of NO_X from nitrogen in the combustion air is dependent on two conditions occurring simultaneously in the unit's combustion zone: high temperature and an excess of combustion air. Under these conditions, significant quantities of NO_X are formed, regardless of the fuel type burned. There are several NO_X emission control strategies that can be considered combustion controls (e.g., low NO_X burners or flue gas recirculation) that reduce the amounts of NO_X formed during combustion. These control technologies are primarily applicable to incomplete combustion fluid catalytic cracking units controlled by CO boilers. As there is limited or no direct flame in the catalyst regenerator during normal operations, these control strategies may be limited for complete combustion fluid catalytic cracking units. Most post-combustion control technologies involve converting the NO_X in the flue gas to N_2 and water using either a process that requires a catalyst (called selective catalytic reduction (SCR)) or a process that does not use a catalyst (called selective noncatalytic reduction (SNCR)). A recently developed post-combustion technology (LoTOx™) uses ozone to oxidize NO_X to nitric pentoxide, which is water soluble and easily removed in a water scrubber.

NO_X Combustion Controls. Flue gas recirculation (FGR) uses flue gas as an inert material to reduce flame temperatures. In a typical FGR system, flue gas is collected from the heater or stack and returned to the burner via a duct and blower. The addition of flue gas with the combustion air reduces the O_2 content of the inlet air stream to the burner. The lower O_2 level in the combustion zone reduces flame temperatures which in turn reduces NO_X emissions. The normal NO_X control efficiency range for FGR is 30 percent to 50 percent. When coupled with low-NO_X burners (LNB), the control efficiency increases to 50–72 percent.

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of O_2, flame temperature, and/or residence time. The two general types of LNB are staged fuel and staged air burners. Staged fuel LNB are particularly well suited for boilers and process heaters burning process and natural gas which generate higher thermal NO_X. The estimated NO_X control efficiency for LNB when applied to petroleum refining fuel burning equipment is generally around 40 percent.

One NO_X combustion control technique that is applicable to complete combustion fluid catalytic cracking units is the use of catalyst additives and/or combustion promoters. The control efficiency of these additives varies from 10 to 50 percent.

Selective Catalytic Reduction (SCR) Technology. The SCR process uses a catalyst with ammonia (NH_3) to reduce the nitrogen oxide (NO) and nitrogen dioxide (NO_2) in the flue gas to N_2 and water. Ammonia is diluted with air or

steam, and this mixture is injected into the flue gas upstream of a metal catalyst bed that typically is composed of vanadium, titanium, platinum, or zeolite. The SCR catalyst bed reactor is usually located between the economizer outlet and air heater inlet where temperatures range from 230 °C to 400 °C (450 °F to 750 °F). The SCR technology is capable of NO_X reduction efficiencies of 90 percent or higher.

Selective Noncatalytic Reduction (SNCR) Technology. An SNCR process is based on the same basic chemistry of reducing the NO and NO_2 in the flue gas to N_2 and water, but it does not require the use of a catalyst to promote these reactions. Instead, the reducing agent is injected into the flue gas stream at a point where the flue gas temperature is within a specific temperature range of 870°C to 1,090°C (1,600°F to 2,000°F). The NO_X reduction levels for SNCR are in the range of approximately 30 to 50 percent.

LoTOx™ Technology. The LoTOx™ process (i.e., low-temperature oxidation) is a patented technology that uses ozone to oxidize NO_X to nitric pentoxide and other higher order NO_X, all of which are water soluble and easily removed from exhaust gas in a wet scrubber. The system operates optimally at temperatures below 300°F. Thus, ozone is injected after scrubber inlet quench nozzles and before the first level of scrubbing nozzles. Outlet NO_X emission levels have been reduced to less than 20 ppmv, and often as low as 10 ppmv, when inlet NO_X concentrations ranged from 50 to 200 ppmv.

B. What is the performance of control technologies for fuel gas combustion?

Refinery fuel gas is generally used in process heaters and boilers to meet the energy demands of the refinery. Excess refinery fuel gas is typically combusted using flares. Flares also serve an important safety function to destroy organics and convert H_2S to SO_2 during process upsets and malfunctions.

Over the past several years, many refineries have reduced flaring episodes by adding flare gas recovery systems and/or by changing their start-up and shutdown procedures to limit flaring. Installing a flare gas recovery system and implementing new start-up and shutdown procedures are expected to reduce VOC, sulfur oxides, and NO_X emissions from flares. Improved amine scrubbing systems are expected to reduce sulfur oxide emissions from all fuel gas combustion systems. In addition, excess capacity in the SRP will help to minimize sour gas flaring that might be caused by a malfunction in the SRP. Each of these ''control'' techniques are described in the following paragraphs.

Flare Gas Recovery Systems. Flare gas recovery systems recover fuel gas from the flare gas header prior to the flare's liquid seal. A flare gas recovery system consists of a compressor, separator, and process controls (to maintain slight positive pressure on the flare header). Flare gas recovery systems are typically designed to recover fuel gas from miscellaneous processes that might regularly be relieved to the flare header system and can effectively recover 100 percent of these fuel gases. However, flare gas recovery systems cannot recover large quantities of fuel gas that might be suddenly released to the flare header system as a result of a process upset or malfunction. These gases would still be flared as necessary to maintain the integrity of the process units and the safety of the plant personnel.

Modified Start-up and Shutdown Procedures. Although flaring is necessary to ensure safety during process upsets and malfunctions, start-up and shutdown procedures can be designed so as to minimize flaring. For example, depressurization of process vessels can be performed more slowly so as to not overwhelm the fuel gas needs of the refinery and/or the capacity of the flare gas recovery system. Depending on the number of units being shut down at a given time, nearly 100 percent of flaring can be eliminated during start-up and shutdown. There are cases, such as emergency shutdowns for safety reasons or approaching hurricanes, where the timing of the shutdown and the magnitude of the number of processes needing to be shut down would warrant the use of flaring. However, modified procedures should be able to eliminate flaring associated with process start-ups and shutdowns due to routine maintenance of select processes.

Amine Scrubbers. Amine scrubber systems remove H_2S and other impurities from sour gas. Lean amine solution absorbs the H_2S from the sour gas in an absorption tower. The acid gas is removed from the rich amine solution in a stripper, or still column. The resulting lean amine is recirculated to the absorption tower, and the stripped H_2S is generally sent to the SRP. Vendors generally provide redundant pumps to ensure continuous operation of the system. Some refineries choose to store a day's worth of lean amine solution in case the stripper fails; this allows the continuous operation of the absorption tower. This option also requires adequate empty storage space for the rich amine solution produced by the absorption tower while the stripper is out of service.

Redundant Sulfur Recovery Capacity. When a sulfur recovery unit (SRU) malfunctions, the sour gas is typically flared to convert the highly toxic H_2S to less toxic SO_2. As many SRU recover more than 20 long tons of elemental sulfur per day, even short sulfur recovery process upsets can result in several tons of SO_2 emissions. Furthermore, refineries often operate multiple Claus sulfur recovery processes in parallel. Having an extra Claus sulfur recovery train can dramatically reduce the likelihood of sour gas flaring. Depending on the severity of the process upset, having a redundant SRU can reduce these large SO_2 releases by as much as 100 percent.

C. What is the performance of control technologies for process heaters?

The mechanisms by which NO_X are formed in process heaters are the same as for their formation in catalyst regenerators. The possible control options are also the same. See section V.A.3 of this preamble for a discussion of these formation mechanisms and control technologies.

D. What is the performance of control technologies for sulfur recovery systems?

Sulfur recovery (the conversion of H_2S to elemental sulfur) is typically accomplished using the modified-Claus process. In the Claus unit, one-third of the H_2S is burned with air in a reaction furnace to yield SO_2. The SO_2 then reacts reversibly with H_2S in the presence of a catalyst to produce elemental sulfur, water, and heat. This is a multi-stage catalytic reaction in which elemental sulfur is removed between each stage, thereby driving the reversible reaction towards completion. The gas from the final condenser of the Claus unit (referred to as the ''tail gas'') consists primarily of inert gases with less than 2 percent sulfur compounds. Additionally, the sulfur recovery pits used to store the recovered elemental sulfur also have a potential for fugitive H_2S emissions. Typically a Claus unit recovers approximately 94 to 97 percent of the inlet sulfur load as elemental sulfur.

There are some methods that extend the Claus reaction to improve the overall sulfur collection efficiency of the SRP. For example, the Superclaus® SRU is similar to the Claus unit. It contains a thermal stage, followed by three to four catalytic reaction stages. The first two or three catalytic reactors use the Claus catalyst, while the last reactor uses a selective oxidation catalyst. The

catalyst in the last reactor oxidizes the H_2S to sulfur at a very high efficiency, recovering 99 percent of the incoming sulfur.

There are a few refineries that operate non-Claus type SRU. All of the refineries that use non-Claus SRU technologies have very low sulfur production rates (2 LTD or less). There are several different trade names for these ''other'' types of SRU, such as the LoCat®, Sulferox®, and NaSH processes. These processes can achieve sulfur recovery efficiencies of 99 percent or more, although they typically yield a sulfur product that has limited market value because the sulfur content is much lower than in the sulfur product from a Claus unit (50 to 70 percent sulfur compared to 99.9 percent sulfur from the Claus process).

The primary means of reducing sulfur oxide emissions from the SRU is to employ a tail gas treatment unit that recovers the sulfur compounds and recycles them back to the inlet of the Claus treatment train. There are three basic types of tail gas treatment units: (1) Direct amine adsorption of the Claus tail gas; (2) catalytic reduction of the tail gas to convert as much of the tail gas sulfur compounds to H_2S (coupled with amine adsorption or Stretford solution eduction); and (3) oxidative tail gas treatment systems to convert the Claus tail gas sulfur compounds to SO_2 (coupled with an SO_2 recovery system).

Direct Amine Adsorption. Direct amine adsorption of the Claus tail gas is the least efficient of the tail gas treatment methods because only about two-thirds of the sulfur in the direct Claus tail gas is amenable to scrubbing (i.e., in the form of H_2S). Direct amine adsorption is therefore expected to increase the overall sulfur recovery efficiency of the sulfur plant to approximately 99 percent. However, direct amine adsorption alone is generally not expected to reduce sulfur oxide concentrations to below 250 ppmv (i.e., enough to meet the existing NSPS emission limits for Claus units greater than 20 LTD).

Reductive Tail Gas Catalytic Systems. The most common reductive tail gas catalytic systems in use at refineries include: (1) The Shell® Claus Offgas Treatment (SCOT) unit; (2) the Beavon/amine system; and (3) the Beavon/Stretford system. Each of these systems consist of a catalytic reactor to convert the sulfur compounds remaining in the Claus tail gas to H_2S and an H_2S recovery system (an amine scrubber or a Stretford solution) to strip the H_2S from the tail gas. The recovered H_2S is then recycled to the front of the Claus unit. The overhead of the amine scrubber or Stretford unit (caustic scrubber) may be vented to the atmosphere or incinerated to convert any remaining H_2S or other reduced sulfur compounds to SO_2. The total sulfur recovery efficiency of a Claus/catalytic tail gas treatment train is expected to be 99.7 to 99.9 percent.

Oxidative Tail Gas Treatment Systems. The Wellman-Lord is the only oxidative tail gas treatment system used in the United States. The Wellman-Lord process uses thermal oxidation followed by scrubbing with a sodium sulfite and sodium bisulfite solution to remove SO_2. The rich bisulfite solution is sent to an evaporator-recrystallizer where the bisulfite decomposes to SO_2 and water and sodium sulfite is precipitated. The recovered SO_2 is then recycled back to the Claus plant for sulfur recovery. The total sulfur recovery efficiency of a Claus/oxidative tail gas treatment train is expected to be 99.7 to 99.9 percent.

E. How did EPA determine the proposed standards for new petroleum refining process units?

Four sources of information were considered in reviewing the appropriateness of the current NSPS requirements for new sources: (1) Source test data from recently installed control systems; (2) applicable State and local regulations; (3) control vendor emission control guarantees; and (4) consent decrees. (A significant number of refineries, representing about 77 percent of the national refining capacity, are subject to consent decrees that limit the emissions from subpart J process units.) Once we identified potential emission limits for various process units, we evaluated each limit in conjunction with control technology, costs, and emission reductions to determine BDT for each process unit.

The cost methodology incorporates the calculation of annualized costs and emission reductions associated with each of the options presented. Cost-effectiveness is the annualized cost of control divided by the annual emission reductions achieved. Incremental cost-effectiveness refers to the difference in annualized cost from one option to the next divided by the difference in emission reductions from one option to the next. For NSPS regulations, the standard metric for expressing costs and emission reductions is the impact on all affected facilities accumulated over the first 5 years of the regulation. Details of the calculations can be found in the public docket. Our BDT determinations took all relevant factors into account, including cost considerations which were generally consistent with other Agency decisions.

1. Fluid Catalytic Cracking Units

Particulate Matter (PM) and Sulfur Dioxide (SO_2). In order to determine the appropriate emission limits for PM and SO_2, we evaluated PM and SO_2 limits in conjunction with one another. One of the reasons for this is that wet scrubbers control both PM and SO_2 emissions, and refineries will decide whether to choose a wet scrubber as opposed to an ESP with catalyst additives based on both the PM and the SO_2 emission limit to be met.

Currently, 40 CFR part 60, subpart J limits PM emissions from the fluid catalytic cracking unit to 1.0 kg/Mg of coke burn-off. The limit applies to filterable PM as measured by Method 5B or 5F in 40 CFR part 60, Appendix A. It excludes condensable PM such as sulfuric acid (under Method 5B), sulfates that condense at temperatures greater than 320 °F (under Method 5F), and all other condensables (using either Method). The measurement of condensable PM is important to EPA's goal of reducing ambient air concentrations of fine PM. Since promulgation of Method 202 in 1991, EPA has been working to overcome problems associated with the accuracy of Method 202 and will promulgate improvements to the method in the future. The existing NSPS also requires opacity, as measured using a continuous opacity monitoring system, to be no more than 30 percent.

The current standards in 40 CFR part 60, subpart J for SO_2 include three alternative formats: (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. The 90 percent reduction, 9.8 kg/Mg, and 0.3 percent feed sulfur formats were determined to be equivalent for a unit operating with a feed that contains 3.5 percent sulfur by weight before implementing a control measure.

In reviewing the PM and SO_2 emission limits, we evaluated five combined options and a baseline. The baseline is considered to be the current requirements, as described in the two previous paragraphs. The first option is to maintain the existing subpart J standard for PM and provide only the 50 ppmv concentration limit for SO_2. The additional options are a range of emission limits coupled with a change in the compliance test method to Method 5 to measure a portion of the

condensable PM. The second option is to combine Method 5 with the existing 1.0 kg/Mg coke burn-off performance level, and a third option is to lower the PM emission limit to 0.5 kg/Mg. Both the second and third options include an SO_2 limit of 50 ppmv. A fourth option includes the PM limit of 0.5 kg/Mg presented in the third option and a lower SO_2 limit of 25 ppmv. The fifth option is to lower the PM emission limit to 0.15 kg/Mg with an SO_2 limit of 25 ppmv. Costs and emission reductions for each option were estimated as the increment between complying with subpart J and subpart Ja.

Option 1 includes the same emissions and requirements for PM as the current 40 CFR part 60, subpart J. For SO_2, this option excludes the alternative compliance options of meeting a higher emission limit without an SO_2 control device or meeting a limit on the sulfur content of the fresh feed. These two alternatives are less stringent than the outlet concentration limit, and available information indicates the concentration limits are achievable. An advantage of the proposed concentration limit is that ongoing compliance can be directly measured using a CEMS. The impacts of this option are limited to the impacts of removing those alternative compliance options for SO_2 and are presented in Table 2 to this preamble. To comply with Option 1 (i.e., meet the 50 ppmv limit for SO_2) we expect that the fraction of new sources choosing wet scrubbers instead of ESP would be greater than under the existing subpart J. Filterable PM emissions are assumed to be the same for both types of control devices because the PM performance levels are the same under both option 1 and the baseline subpart J requirements. However, because condensable PM emissions are lower from wet scrubbers than from ESP, this shift in the ratio of wet scrubbers to ESP would also result in an estimated reduction in total PM emissions of 17 tons per year, as shown in Table 2 to this preamble.

Option 2 includes the same emission limit as current subpart J for PM but requires compliance using Method 5 rather than Method 5B or Method 5F. As noted above, Methods 5B and 5F exclude all PM that condenses at temperatures below 320°F, and Method 5F also excludes sulfates that condense at temperatures greater than 320°F. The PM measured by Method 5 includes filterable PM that condenses above 250°F in the front half of the Method 5 sampling train. Thus, the estimated PM emission reductions achieved by this option equal 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. The baseline emissions were estimated assuming Method 5B is used for wet scrubbers and Method 5F is used for ESP. For SO_2, Option 2 includes the same emission limit as described in Option 1, and the estimated SO_2 emission reductions are also the same. The impacts of this option are presented in Table 2 to this preamble.

Option 3 lowers the PM limit to 0.5 kg/Mg coke burn, again using Method 5, and includes the same emission limit as described in Option 1 for SO_2. The existing NSPS limit was based on control with ESP. Those ESP were rated at efficiencies of only 85 to 90 percent. More recently installed ESP have greater specific plate area, which should result in better control efficiencies. In addition, many refineries have installed wet scrubbers to control both PM and SO_2. At petroleum refineries, wet scrubbers typically perform as well as, if not better than, ESP. Available test data indicate that at least one ESP and one wet scrubber are reducing total filterable PM to 0.5 kg/Mg of coke burn or less, as measured by Method 5-equivalent test methods. Based on this information, both ESP and wet scrubbers can achieve PM emission levels below the level of the existing PM standard, and a lower standard for new units is technically feasible. The impacts of this option are presented in Table 2 to this preamble.

Option 4 includes the same PM limit as Option 3, and the discussion presented for Option 3 applies to Option 4 as well. It also includes a long-term limit for SO_2 of 25 ppmv, averaged over 365 days, in addition to the current subpart J limit of 50 ppmv, averaged over 7 days. These limits have been shown to be readily achievable by flue gas desulfurization systems. Many fluid catalytic cracking units are now subject to consent decrees that require control to these levels. Petroleum refiners typically use wet scrubbers to control SO_2 emissions, and test data indicate that outlet concentrations below 25 ppmv are common. At least one wet scrubber manufacturer also provides performance guarantees to meet a 25 ppmv emission limit. The incremental SO_2 reductions for this option relative to Option 3 are achieved by using catalyst additives in the fluid catalytic cracking units that are assumed to be controlled with ESP; fluid catalytic cracking units controlled with wet scrubbers have the same SO_2 emissions as under Option 3 because wet scrubbers under all options are assumed to achieve SO_2 emissions below 25 ppmv. The impacts of this option are presented in Table 2 to this preamble.

The final option, Option 5, includes a lower PM limit, 0.15 kg/Mg of coke burn, measured using Method 5, and the same SO_2 limits as Option 4. This PM limit is equivalent to the limit of 0.005 gr/dscf required by California's South Coast Air Quality Management District (SCAQMD). To meet this PM limit, we expect that a refinery would need an ESP rather than a wet scrubber because we are unaware of any wet scrubber that is meeting this PM limit (and as in Option 4, catalyst additives in the fluid catalytic cracking unit would be needed to meet the SO_2 limit). In addition, the refinery would likely need ammonia injection to improve the performance of the ESP. Based on test data from at least three fluid catalytic cracking units, ammonia injection improves the control of filterable PM in ESP, but it also produces a considerable amount of condensable PM. Therefore, the estimated total PM reduction for this option is much lower (worse) than the reduction that would be achieved under Option 4. The shift to ESP for all new fluid catalytic cracking units under this option also slightly degrades the estimated SO_2 emissions reduction relative to Option 4 because available data indicate that wet scrubbers achieve lower SO_2 emissions than ESP and catalyst additives. In addition to reduced performance relative to Option 4, the capital and annual costs of this option are considerably higher than for Option 4. The reduced performance of this option relative to Option 4 means that incremental cost-effectiveness is not meaningful for this option. The impacts of this option are presented in Table 2 to this preamble.

TABLE 2.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR PM AND SO_2 LIMITS CONSIDERED FOR FLUID CATALYTIC CRACKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons PM/yr) [a]	Emission reduction (tons SO_2/yr)	Cost-effectiveness ($/ton)	
					Overall	Incremental
1	500	3,100	17	6,800	460	
2	670	3,600	350	6,800	500	1,400
3	40,000	9,200	1,200	7,200	1,100	4,400
4	40,000	9,500	1,200	8,300	1,000	220
5	140,000	30,000	460	7,900	3,600	N/A

[a] Both filterable and condensable PM.

Based on our review of performance data and potential impacts, we have determined that control of PM emissions (as measured by Method 5) to 0.5 kg/Mg of coke burn or less and 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. The more stringent filterable PM control level in Option 5 is technically achievable, but we rejected this option because it results in higher total PM and SO_2 emissions than Option 4. Option 4 was selected as BDT because it achieves the best performance of the remaining options, and both overall and incremental costs are reasonable.

Table 3 to this preamble shows the impacts of Option 4 for modified and reconstructed sources. Although the impacts of Option 4 are reasonable, we are aware that there is some concern about the ability to retrofit reconstructed and modified sources to meet these emission limits. Specifically, there may be issues with physical space availability, process unit or control device configurations, or other factors that are not adequately included in our impacts analyses. Therefore, we are co-proposing requiring reconstructed and modified units to meet the current standards in 40 CFR part 60, subpart J. We are requesting comment on specific examples, supported by data, of situations that would support this proposed option.

TABLE 3.—NATIONAL FIFTH YEAR IMPACTS OF PROPOSED OPTION FOR PM AND SO_2 LIMITS FOR RECONSTRUCTED AND MODIFIED SOURCES

Capital cost ($1,000)	Total annual cost ($1,000/yr)	Emission reduction (tons PM/yr)	Emission reduction (tons SO_2/yr)	Cost-effectiveness ($/ton)
31,000	6,200	700	3,700	1,400

Finally, available test data indicate that the two control devices (an ESP and a wet scrubber) that reduce filterable PM to less than 0.5 kg/Mg coke burn (as well as at least one other ESP) also can meet a total PM limit, including condensables, of 1.0 kg/Mg of coke burn (i.e., demonstrate compliance using Method 5 for filterable PM and Method 202 for condensable PM). Condensable sulfates and other condensable compounds measured by Method 5 and Method 202 vary widely, but the average is about 0.5 kg/Mg of coke burn-off. In an attempt to create some incentive to begin measuring condensables using improved Method 202, we are considering establishing an alternative PM limit of 1 kg/Mg coke burn, including condensables. Therefore, we are asking for comments with rationale to either support or reject an alternative PM limit that would be based on both filterable PM and condensable PM.

Carbon Monoxide. The current standards in 40 CFR part 60, subpart J limit CO emissions to 500 ppmv or less. This limit was established for fluid catalytic cracking units that operate in either ''partial combustion'' catalyst regeneration mode or ''complete combustion'' catalyst regeneration mode. In partial combustion mode, relatively large amounts of CO are generated in the regenerator. The resulting CO is then combusted in a CO or waste heat boiler. This operation results in nearly complete combustion of the CO, with outlet concentrations on the order of 25 to 50 ppmv being common. In complete combustion mode the CO emissions from the regenerator are much lower, and a downstream CO or waste heat boiler is impractical. However, complete combustion catalyst regeneration was a recent advance at the time the current NSPS was promulgated; test data were limited at that time, and a CO level of 500 ppmv was estimated to be a practical limit for the technology.

After consideration of available information, we are proposing to retain the current CO standard for new fluid catalytic cracking units. Although test data show CO emissions from complete combustion regenerators can be less than 500 ppmv, the lower levels generally are achieved by operating with higher levels of excess air. Unfortunately, this operation is likely to result in higher NO_X emissions. If a trade-off is necessary, limiting NO_X emissions is a higher priority than limiting CO emissions because NO_X is a precursor to fine PM and ground-level ozone, both of which have more significant health impacts than CO. Available data also indicate that formaldehyde emissions tend to increase with the higher oxidation/combustion conditions needed to reduce CO emissions. Therefore, we determined that control to 500 ppmv or less is still BDT for CO emissions, and the proposed standards are based on this emission limit. Accordingly, the proposed limit for 40 CFR part 60, subpart J poses no additional costs over those incurred to comply with the existing NSPS.

NO_X. NO_X emissions are not subject to control under the existing NSPS in 40 CFR part 60, subpart J. However, several petroleum refiners limit NO_X emissions based on State regulations and consent decrees. The emission limits to which refineries are subject vary from facility to facility. We evaluated three options

as part of the BDT determination: Outlet NO_X emission levels of 80 ppmv, 40 ppmv, and 20 ppmv, each averaged over 7 days or less. Each of these limits is technically feasible, but the technology needed to meet them depends on the current NO_X concentrations in the vented gas streams, which are either uncontrolled or controlled to levels required by existing State and local requirements.

The estimated fifth year emission reductions and costs for each of the options are summarized in Table 4. To estimate impacts for Option 1, we assumed that a few units have current NO_X emissions below 80 ppmv, and many other units can meet this level with combustion controls (e.g., limiting excess O_2 or using non-platinum catalyst combustion promoters in a complete combustion catalyst regenerator, or using flue gas recirculation or low-NO_X burners in a CO boiler after a partial combustion catalyst regenerator). Other units with higher uncontrolled NO_X emissions levels will need to install more costly control technology such as LoTOx™ or SCR in order to meet the 80 ppmv option. All units will also incur costs for a continuous NO_X monitor. The costs for Options 2 and 3 are higher than for Option 1 because the ratio of add-on controls to combustion controls would increase in order to meet the lower limits of 40 and 20 ppmv.

Based on the impacts shown in Table 4, we determined that BDT is option 1, a NO_X emission limit of 80 ppmv. The costs of option 1 are commensurate with the emission reductions while the more stringent options would impose compliance costs that are not warranted for the emissions reductions that would be achieved as shown by the incremental cost effectiveness impacts shown in table 4. In general, we expect that most sources will be able to meet the NO_X limit through combustion controls. In cases where add-on controls would be necessary, however, there may be retrofit concerns for modified and reconstructed sources. Therefore, we are co-proposing no new standards for NO_X emissions on modified or reconstructed sources and are requesting comments on the necessity, feasibility and costs of retrofits to meet the 80 ppmv limit for modified and reconstructed sources.

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

Option	Total capital cost, $ (millions)	Total annual cost, $/yr (millions)	Emission reduction, tons NO_X/yr	Cost effectiveness ($/ton)	
				Overall	Incremental
1	28	7.3	3,500	2,100	.....
2	80	20	5,200	4,200	7,600
3	120	30	5,800	5,500	16,000

Available test data for units controlled with SCR indicate that emissions less than 20 ppmv are continuously achievable when averaged over long periods of time such as 365 days. Although we determined that the average costs to meet such a limit are unreasonable, we are requesting comment on whether there may be a subset of units for which costs would be reasonable to meet lower limits such as 20 or 40 ppmv, averaged over 365 days.

Opacity. The current standards require fluid catalytic cracking units to meet an opacity limit of 30 percent. This limit was included as a means of identifying failure of the PM control device. This objective is achieved much more effectively by monitoring control device operating parameters or by using a PM CEMS. These monitoring options are included in the proposed standards for PM. Therefore, the proposed standards do not include an opacity emissions limit.

2. Fluid Coking Units

The current NSPS includes no requirements for fluid coking units. There are few fluid coking units at refineries in the U.S., but data in the National Emission Inventory database shows the few existing units are significant sources of PM, SO_2, and NO_X emissions. Therefore, we evaluated several options as part of a BDT determination for fluid coking units. All of the options we considered are comparable to options that we considered for fluid catalytic cracking units because of similarities in the function, operation, and emissions of the two types of units.

Particulate Matter and Sulfur Dioxide. To determine BDT for PM and SO_2 emissions we evaluated two options. Because control technology can reduce both pollutants simultaneously, the options also consider both pollutants. Option 1 is a PM limit of 1.0 kg/Mg coke burn and a short-term SO_2 limit of 50 ppmv, averaged over 7 days; and Option 2 is a PM limit of 0.5 kg/Mg coke burn, 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. (Because catalyst additives are not a feasible option for reducing SO_2 from a fluid coking unit, we did not consider the fifth option evaluated for fluid catalytic cracking units.)

The Energy Information Administration (EIA) Refinery Capacity Report 2006 lists six fluid coking units; at least two of these coking units are flexi-coking units that use the coking exhaust as a synthetic fuel gas. Therefore, there are at most four fluid coking units in the United States that could potentially become subject to the standard. Although coking capacity is expected to increase, most new units are expected to be delayed coking units. For this analysis, we assumed that one existing fluid coking unit becomes a modified or reconstructed source in the next 5 years. A wet scrubber is the most likely technology that would be used to meet either Option 1 or Option 2. To estimate the impacts, we estimated costs for a basic wet scrubber to meet Option 1 and an enhanced wet scrubber to meet Option 2. The resulting emission reductions and costs for both of the options are shown in Table 5 to this preamble. The costs for both options are reasonable. Therefore, we determined that BDT is Option 2 which requires technology that reduces PM emissions to 0.5 kg/Mg of coke burn and reduces SO_2 emissions to 50 ppmv, averaged over 7 days, and 25 ppmv, averaged over 365 days. We are proposing standards consistent with these levels.

TABLE 5.—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)	
					Overall	Incremental
1	14,000	4,700	1,700	21,000	210	.....
2	14,000	4,800	2,000	21,000	210	120

Nitrogen Oxides (NO_X). To determine BDT for NO_X emissions, we evaluated three options: Outlet NO_X emission levels of 80 ppmv, 40 ppmv, and 20 ppmv, each averaged over 7 days or less. The specific technology that will be needed to meet these levels will depend on the NO_X concentration in the exhaust gas stream from uncontrolled fluid coking units. As noted in the discussion above for PM and SO_2 options, we estimated that only one fluid coking unit will be modified or reconstructed in the next 5 years, and there will be no new units constructed. Because each unit is likely to have a different uncontrolled NO_X concentration in its exhaust stream, we developed impacts for a composite model unit based on a weighted distribution of all the various types of controls (low-efficiency combustion controls, higher efficiency combustion controls, and add-on controls such as LoTox™ or SCR). As in the analysis for fluid catalytic cracking units, the ratio of add-on controls to combustions controls increases from Option 1 through Option 3. The results of this analysis are shown in Table 6 to this preamble.

TABLE 6.—NATIONAL FIFTH YEAR IMPACTS OPTIONS FOR NO_X LIMITS CONSIDERED FOR FLUID COKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Total capital cost, $ (millions)	Total annual cost, $/yr (millions)	Emission reduction, (tons NO_X/yr)	Cost-effectiveness ($/ton)	
				Overall	Incremental
1	4.5	0.97	760	1,300	
2	9.5	2.1	980	2,200	5,300
3	13	2.9	1,000	2,800	12,000

The costs for option 1 are commensurate with the emission reductions, but the incremental impacts for options 2 and 3 are not reasonable, as shown in Table 6. Based on these potential impacts and available performance data, we have determined that BDT is technology needed to meet an outlet NO_X concentration of 80 ppmv or less, and we are proposing this emission limit as the performance standard for NO_X emissions from fluid coking units. However, there are uncertainties in this analysis. For example, if the few existing units are not readily amenable to retrofitting NO_X controls, the cost and emission reduction impacts might no longer be favorable, and we would conclude that no control is BDT. Therefore, we are co-proposing no new standard for NO_X emissions from fluid coking units.

3. Sulfur Recovery Plants

Emission limits in the existing NSPS (40 CFR part 60, subpart J) apply to Claus SRP with a capacity greater than 20 LTD. The emission limits are consistent with an overall sulfur recovery efficiency of 99.9 percent (*i.e.*, 250 ppmv SO_2 for the Claus unit followed by oxidative tail gas treatment, and 10 ppmv H_2S and 300 ppmv total reduced sulfur compounds for a Claus unit followed by reductive tail gas treatment). Although small SRP and non-Claus SRP are not subject to the existing NSPS, they are often subject to control. For example, Texas requires sulfur removal efficiencies of 99.8 percent for SRP with capacities greater than 10 LTD and 96 percent to 98.5 percent for SRP with capacities less than or equal to 10 LTD. In addition, a few consent decrees require 95 percent sulfur recovery for Claus SRP with capacities less than 20 LTD.

To determine BDT we evaluated 4 options. The options are based on various sulfur recovery efficiencies for SRP with capacities less than 20 LTD, and all of the options include the same 99.9 percent efficiency as in the current standards for SRP with capacities greater than 20 LTD. Option 1 is based on 99 percent recovery for SRP with capacities between 10 LTD and 20 LTD, and 95 percent recovery for SRP with capacities less than 10 LTD. Option 2 is based on 99 percent recovery for all SRP with capacities less than 20 LTD. Option 3 is based on 99.9 percent recovery for SRP with capacities between 10 LTD and 20 LTD, and 99 percent recovery for SRP with capacities less than 10 LTD. Option 4 is based on 99.9 percent recovery for all SRP, regardless of size or design. All of the options include 99.9 percent recovery for SRP larger than 20 LTD (both Claus and non-Claus units) because we are not aware of a more effective SO_2 control technology. The 95 percent option is equivalent to the efficiency of a two-stage Claus unit without controls. The 99 percent and 99.9 percent recovery levels are achievable for SRP of all sizes by various types of tail gas treatments, as discussed in section V.D of this preamble.

The estimated fifth year emission reductions and costs for each of the options are summarized in Table 7. These values reflect the impacts only for SRP smaller than 20 LTD because we expect that all non-Claus units will be smaller than 20 LTD and because the impacts for larger Claus units would be the same as to comply with the existing standards in subpart J. The costs for Options 1, 2, and 3 are reasonable. We then evaluated the incremental costs and emission reductions between the options. We found that Option 2 is the most stringent option for which incremental costs are reasonable compared to the incremental emission reduction between the options.

Based on the available performance data and cost considerations, we have concluded that tail gas treatments that achieve 99.9 percent control are still

BDT for SRP with capacities greater than 20 LTD, and tail gas treatments that achieve 99 percent recovery are BDT for SRP with capacities less than 20 LTD. Therefore, we are proposing standards for SO_2 and H_2S emissions from SRP with capacities larger than 20 LTD that are equivalent to the existing standards, and we are proposing standards for SRP with capacities smaller than 20 LTD that would limit emissions of sulfur to less than 1 percent by weight of the sulfur recovered.

TABLE 7.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR SO_2 LIMITS CONSIDERED FOR SULFUR RECOVERY PLANTS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Total capital cost, $ (millions)	Total annual cost, $/yr (millions)	Emission reduction, (tons SO_2/yr)	Cost-effectiveness ($/ton)	
				Overall	Incremental
1	0.27	0.14	180	780	
2	1.1	0.68	550	1,200	1,500
3	1.9	1.0	590	1,700	8,200
4	4.5	2.3	670	3,400	15,000

4. Process Heaters and Other Fuel Gas Combustion Devices Sulfur Dioxide

The current NSPS in 40 CFR part 60, subpart J limits SO_2 emissions from fuel gas combustion devices by specifying that the H_2S content of fuel gas must be less than or equal to 230 mg/dscm, averaged over 3 hours (equivalent to 160 ppmv averaged over 3 hours). Alternatively, any fuel gas may be combusted, provided the outlet SO_2 emissions are controlled to no more than 20 ppmv (dry basis, 0 percent excess air). When the current NSPS was promulgated, we concluded that amine scrubbing as well as new processes that use other scrubbing media represented BDT for continuous reduction of H_2S from fuel gas. The 160 ppmv concentration limit was consistent with good operation of such scrubbing processes. In addition, burning such fuel gas will result in an SO_2 concentration in the exhaust gas of about 20 ppmv.

After consideration of current operating practices, we concluded that amine scrubbing units are still the predominant technology for reduction of H_2S in fuel gas (and SO_2 emissions from subsequent fuel gas combustion). Considering the variability of the fuel gas streams from various refinery processing units, 160 ppmv also is still a realistic short term H_2S concentration limit. However, one California Air Quality Management District rule sets a 40 ppmv H_2S limit in fuel gas (averaged over 4 hours), and several refiners have reported that the typical fuel gas H_2S concentrations (after scrubbing) are in the same range. Additionally, amine scrubbing technology can be designed and is, in fact, being used to achieve much lower (1 to 5 ppmv) H_2S concentrations in product gas applications. Based on this information, we concluded that additional SO_2 control could be achieved by requiring SO_2 emission limits with both long-term and short-term averaging periods.

We considered three options for increasing SO_2 control of fuel gas combustion units: Outlet SO_2 emission levels of 10 ppmv, 8 ppmv, and 5 ppmv SO_2, each averaged over 365 days. Each of the options also includes the same 20 ppmv 3-hour SO_2 concentration limit as in the current NSPS. To achieve each of these options, we expect that petroleum refiners will increase their amine recirculation rates to reduce the H_2S concentration in the fuel gas. We estimate that meeting the options will increase steam consumption for a typical scrubbing unit by about 5, 7, and 10 percent, respectively. No new equipment or other capital expenditures would be necessary. The estimated fifth-year impacts of each of these options are presented in Table 8 to this preamble. Overall costs for all the options are reasonable compared to the emission reduction achieved. We further evaluated the incremental costs and reductions between the 3 options and found that they were reasonable for Options 1 and 2, while the incremental cost for Option 3 is not.

TABLE 8.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR SO_2 LIMITS CONSIDERED FOR PROCESS HEATERS AND OTHER 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
1	0	2,000	1,000	1,900	
2	0	2,900	1,300	2,200	3,500
3	0	4,100	1,600	2,600	4,700

Based on these impacts and consideration of current operating practices, we concluded that BDT is use of technology that reduces the SO_2 emissions from fuel gas combustion units to 8 ppmv or less averaged over 365 days and 20 ppmv or less averaged over 3 hours. Therefore, we are proposing SO_2 standards consistent with this determination. We are also requesting comment on the proposed long-term concentration limit and the length of the averaging period.

Although the proposed emission limits are based primarily on the fuel gas desulfurization technologies (e.g., amine scrubbing), new process heaters, regardless of fuel type, also would be subject to these emission limits. New process heaters can elect to meet these emission limits by using treated fuel gas, low sulfur distillate fuel oils, or flue gas desulfurization or other SO_2 add-on controls. Considering the low sulfur fuel standards and available control technologies, we believe the 20 ppmv 3-hour average SO_2 emission limit and an

8 ppmv 365-day average emission limit represent the performance of BDT regardless of whether the new process heaters use gaseous or liquid fuels.

The current NSPS allows refineries to demonstrate compliance with fuel gas concentration limits for H_2S as a surrogate for SO_2 emission limits. This approach is reasonable when H_2S is the only sulfur-containing compound in the fuel gas because the H_2S concentration in the fuel gas that is equivalent to the SO_2 concentration in the exhaust from the fuel gas combustion unit can be easily estimated. However, based on available data, we understand that a significant portion of the sulfur in fuel gas from coking units is in the form of methyl mercaptan and other reduced sulfur compounds. These compounds will also be converted to SO_2 in the fuel gas combustion unit, which means the SO_2 emissions will be higher than the amount predicted when H_2S is the only sulfur-containing compound in the fuel gas. Therefore, for process heaters and other fuel gas combustion devices that burn only fuel gas, we are proposing two alternatives to the SO_2 emission limit. The first option would require measurement of H_2S if none of the fuel gas is from a coking unit. The H_2S concentration limits that would be equivalent to the SO_2 emission limits are 160 ppmv, averaged over 3 hours, and 60 ppmv averaged over 365-days. The second option would require measurement of TRS instead of H_2S when any of the fuel gas burned in the process heater or other fuel gas combustion unit is from a coking unit. The TRS concentration limits would be the same as the H_2S concentration limits. We are requesting comment on the proposed requirement to measure the TRS concentration. We are interested in any technological limitations of this option and whether there are other fuel gas streams that contain reduced sulfur compounds that should not be subject to the same requirement.

In addition to the proposed SO_2 emission limits and H_2S and TRS concentration limits, we are also proposing to include the same exemptions from fuel gas continuous monitoring requirements that we are proposing for subpart J. See section IV.A of this preamble for a discussion of our rationale for these proposed exemptions.

NO_X. NO_X emissions from process heaters are not subject to control under the existing NSPS in 40 CFR part 60, subpart J. However, several petroleum refiners are subject to NO_X control requirements for process heaters in their consent decrees and State regulations. The emission limits to which refineries are subject vary from facility to facility. We evaluated four options as part of the BDT determination. Each option consists of a potential NO_X emission limit and applicability based on process heater size. Option 1 would limit NO_X emissions to 80 ppmv or less for all process heaters with a capacity greater than 20 million British thermal units per hour (MMBtu/hr). Option 2 would limit NO_X emissions to 40 ppmv or less for all process heaters with a capacity greater than 20 MMBtu/hr. Option 3 would limit NO_X emissions to 30 ppmv or less for all process heaters with a capacity greater than 40 MMBtu/hr. Option 4 would limit NO_X emissions to 40 ppmv or less for process heaters with a capacity greater than 20 MMBtu/hr or less than or equal to 100 MMBtu/hr, and to 20 ppmv or less for process heaters with a capacity greater than 100 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 are summarized in Table 9. We believe that nearly all process heaters at refineries that will become subject to subpart Ja can meet Option 1 using combustion controls (low NO_X burners or ultra low NO_X burners). Stepping from Option 1 through Option 4 increases the fraction of process heaters that would need to use more efficient control technologies, such as LoTOx™ or SCR, to meet the NO_X concentration limit. The options include a minimum 20 MMBtu/hr size threshold because none of the control technologies are cost effective for units with smaller capacities.

TABLE 9.—NATIONAL FIFTH YEAR IMPACTS OPTIONS FOR NO_X LIMITS CONSIDERED FOR PROCESS HEATERS SUBJECT TO 40 CFR PART 60, SUBPART JA

Option	Total capital cost, $ (millions)	Total annual cost, $/yr (millions)	Emission reduction, (tons NO_X/yr)	Cost effectiveness ($/ton)	
				Overall	Incremental
1	140	28	17,000	1,600	.....
2	200	38	20,000	1,900	3,100
3	280	52	21,000	2,600	85,000
4	470	88	22,000	4,000	27,000

Based on the impacts in Table 9, the overall costs of option 1 and option 2 are reasonable compared to the emission reductions. The incremental cost, however, between options 1 and 2 is not commensurate with the additional emission reduction achieved. Therefore, BDT for process heaters greater than 20 MMBtu/hr was determined to be technology that achieves an outlet NO_X concentration of 80 ppmv or less, and we are proposing standards for NO_X emissions from process heaters consistent with this determination.

5. Work Practice Standards for Fuel Gas Production Units

We reviewed applicable state and local regulations and consent decree requirements and met with individual refinery representatives regarding their pollution prevention practices. The pollution prevention practices identified included flare minimization plans, fuel gas recovery requirements, start-up and shutdown requirements, and sulfur shedding plans (including redundant sulfur recovery capacity). Based on our review, all of these approaches could be expected to reduce emissions of VOC and SO_2 to the atmosphere. As described in the following subsections, we reviewed these pollution prevention practices and are proposing three different work practice standards. Work practice standards are being proposed because it is not feasible to prescribe or enforce a standard of performance for these emission sources. As provided in section 111(h) of the Clean Air Act, we may promulgate design, equipment, work practice, or operational standards when it is not feasible to prescribe or enforce a standard of performance. It is not feasible to prescribe or enforce a standard of performance for these

sources because either the pollution prevention measures eliminates the emission source, so that there are no emissions to capture and convey, or the emissions are so transient, and in some cases, occur so randomly, that the application of a measurement methodology to these sources is not technically and economically practical.

Elimination of Routine Flaring. Flares are first and foremost a safety device used to reduce emissions from emergency pressure relief of gases from refinery process units. We in no way want to limit the use of flares for emergency releases. However, many refineries also routinely use flares as an emission control device under normal operating conditions.

Fuel gases produced within the refinery can be roughly divided into two categories based on the fuel gas stream pressure. Fuel gases produced in processes operated at higher pressures are easily routed to the fuel gas system; however, fuel gases that are produced from units operated near atmospheric pressures are not as easily routed to the fuel gas system. These ''low pressure'' fuel gases are often routed to flares because the flare gas system operates at a much lower pressure than the fuel gas system. Flare gas recovery systems are designed to compress the low pressure fuel gases, creating a high pressure fuel gas stream that can readily be added to the fuel gas system.

In 1998, the South Coast Air Quality Management District developed a rule requiring refineries to measure the flow rate and hydrocarbon content of the gases sent to a flare. This South Coast rule, although it did not set prescriptive emission limits, led to reduced flaring as refinery operators, armed with the monitoring results, identified cost-effective flare gas minimization or recovery projects. In 2005, South Coast amended this rule and established a no routine flaring goal based on the cost and anticipated emission reductions of flare gas recovery systems. The Bay Area Air Quality Management District also adopted a rule requiring flare monitoring in 2003 and adopted a rule to minimize flaring in 2006.

We considered adopting the South Coast and Bay Area rules for this NSPS for new flare systems. However, many refinery flares operate for 50 years, so very few flares or flare systems are expected to become subject to NSPS requirements, even after several decades. Instead, we are proposing to add ''fuel gas producing units'' as a new affected source under subpart Ja and focus the requirement on eliminating routine flaring of fuel gas at the process units producing the fuel gas. A refinery owner or operator installing a new process unit that produces low pressure fuel gas has options for eliminating routine flaring, including, but not limited to, diverting the fuel gas to a nearby low-pressure heater or boiler, pressurizing the fuel gas so that it can be diverted to the fuel gas system, or installing a flare gas recovery system. The proposed work practice standard is designed to allow flexibility in compliance approaches without imposing undue restrictions on the use of flares during malfunctions or other conditions wherein flaring is the best environmental management practice considering the safety of the plant personnel and surrounding people. Additionally, several new fuel gas producing units are expected to be installed every year, so by regulating the fuel gas producing units we not only provide flexibility, but we also increase the rate at which the no routine flaring requirement is implemented within the industry.

The impacts for this work practice are highly dependent on the amount of fuel gas generated by different fuel gas combustion units. Recovered fuel gas reduces the amount of natural gas a refinery must purchase to operate their process heaters. For example, fuel gases generated by fluid catalytic cracking units and coking units are routinely recovered into the fuel gas system due to the quantity of fuel gas generated in the process. For these systems, the savings associated with the recovered fuel gas provides a return on the capital investment associated with the compressor and ancillary equipment needed to recover the fuel gas. For other fuel gas producing units, such as reforming units, it is possible to route the fuel gas directly to the unit's process heater without additional gas compression. For a few refineries, a flare gas recovery system may be used.

We estimated planning and design costs for assessing methods to recover or otherwise avoid the release of fuel gas from new fuel gas producing units. As described previously, for many fuel gas producing units, the cost savings associated with the recovered fuel recovers the costs of the recovery equipment within the life-span on the equipment so that the annualized cost of controls is zero or slightly negative (indicating a cost savings). As a worst-case scenario, we used the impacts developed by the Bay Area for a system-wide flare gas recovery system. The total annualized cost of the system was estimated to be approximately $2 million; no credit was provided for the heating value of the flare gas recovered. VOC emission reductions were estimated to be approximately 1,000 tons per year and SO_2 emissions were estimated to be 3,500 tons per year. The cost-effectiveness on the flare gas recovery system was estimated to be approximately $2,000/ton of VOC removed and approximately $570/ton of SO_2 removed, assuming total costs are assigned to each pollutant. Therefore, even when fuel credits are not considered, flare gas recovery is cost-effective as an emissions control device. When properly sized, these flare gas recovery systems can eliminate all routine flaring. Therefore, eliminating routine flaring by use of fuel gas recovery, in-process fuel use, or system wide flare gas recovery is determined to be BDT.

We request comment on alternative means of eliminating routine flaring. As noted previously, a simple requirement to monitor gas flow and composition of gases sent to the flares resulted in reduced use of flares. An exemption from this monitoring requirement for flare systems that install flare gas recovery could provide refineries an incentive to install flare gas recovery systems. We request comment on this alternative and on the need to monitor flares that have flare gas recovery systems to ensure that the flare gas recovery system is properly sized and that no routine flaring is occurring.

Additionally, we understand that there are a limited number of refineries that produce more fuel gas than they can use in the refinery process heaters or steam boilers. These ''fuel gas rich'' refineries contend that flaring is BDT for these refineries. Although we believe that other options exist, such as building an electric co-generating unit, the cost-effectiveness of such an endeavor is very site-specific. We cannot conclude at this time that co-generation or other projects that use fuel gas are BDT. Therefore, we are co-proposing no requirement for fuel gas producing units. We request comment on the actual number and location of ''fuel gas rich'' refineries. We also request comment and data regarding the technical and economical feasibility of alternatives for ''fuel gas rich'' refineries to avoid routine flaring.

Emission Prevention During Start-up, Shutdown, and Malfunctions. The current NSPS includes no requirements for a start-up, shutdown, and malfunction plan. We identified three emission prevention methods that can be addressed within the context of a start-up, shutdown, and malfunction plan. These are: Flare minimization during planned start-ups and shutdowns; flare minimization during malfunctions of the sour gas amine

treatment units and sulfur recovery plants; and performing root-cause analyses of malfunctions that release in excess of 500 lb per day of SO_2. Our rationale for including each of these three emission prevention methods are described in the following paragraphs.

Flaring and direct venting of certain gas streams have been routinely used during planned start-up and shutdown of process units to quickly bring a process unit online or offline. These flaring and venting episodes have traditionally been exempt from any emission limitations. Nonetheless, some refineries have chosen to evaluate their start-up and shutdown emissions and alter their procedures so as to reduce or eliminate direct venting or flaring during planned start-up and shutdown events.

Typically, alternative start-up and shutdown procedures that reduce atmospheric emissions or flaring require more time to complete than conventional procedures. Therefore, there is a cost associated with the alternative procedures in terms of potential product/productivity loss. For refineries that have system-wide flare gas recovery systems, it may be a simple matter of scheduling the start-up or shutdown during a time when limited other flare gas is being generated so as to not overwhelm the flare gas recovery system. The cost-effectiveness of the alternative procedures would depend on the amount of gas flared or vented using the traditional procedures, the amount of these emissions that can be avoided using alternative procedures, the amount of product lost due to the increased start-up/shutdown time period, and the value of that product. As such, it is difficult to conclude that significant or complete emission reductions during planned start-up or shutdown events will be cost-effective under all conditions; therefore, we chose not to set a specific venting or flaring limit (or prohibition).

We estimate that the engineering review revision of a unit's start-up and shutdown plan would require approximately 20 engineering hours per process unit, at total cost of $1,300 to $1,500 per process unit (one-time costs). Assuming the unit requires maintenance shut-down only once every 5 years and the revised procedures only reduce VOC and SO_2 emissions by 1 ton each per event, the cost-effectiveness of the engineering review is $1,300 to $1,500 per ton of VOC and the same for SO_2.

Based on this simplistic analysis, we are proposing that implementing a start-up and shutdown plan focused on reducing emissions during planned start-up and shutdown events would be BDT.

We evaluated several different requirements to promote continuous compliance with the SO_2 emission limits associated with fuel gas combustion devices and sulfur recovery plants even during times of process upsets or malfunctions associated with the amine system or sulfur recovery plant. ''Process upset gas'' is ''gas *generated* by a petroleum refinery process unit as a result of upset or malfunction.'' Process upset gas is exempt from the SO_2 emission limits. However, when there is a malfunction of the amine treatment system or the sulfur recovery plant, there has been some uncertainty as to whether combustion or flaring of the sour gas is considered to be exempt from the SO_2 emission limit. This is because the amine treatment system or sulfur recovery plant is not ''generating'' the gas stream, it is merely treating it. As such, the amine treatment system and sulfur recovery plant are essentially control devices, and refinery owners and operators are required to minimize emissions during these control system malfunctions, up to and including the shutdown of the emissions generating units.

A variety of prescriptive requirements were reviewed, such as requiring 24-hour storage capacity of lean amine solution and empty tank storage capacity to receive 24 hours worth of rich amine solution, requiring inventory of critical spare parts, and requiring redundant amine scrubbing and sulfur recovery capacity. While these are all viable options that a plant can employ to minimize malfunction emissions associated with the amine treatment system or sulfur recovery plant, the most cost-effective means to minimize these emissions are highly site-specific, being dependent on the number and location of the amine units or sulfur recovery trains within the sulfur recovery plant.

We evaluated two alternatives, which are not mutually exclusive, for minimizing flaring of H_2S-rich fuel gas in the event of a malfunction in the amine stripper or sulfur recovery plant. Option 1 is to store 24 hours worth of lean amine solution in case of a malfunction in the amine stripper. We estimate that this alternative would require a capital cost of approximately $10 million (for 2 storage tanks and excess amine) for a 50 long LTD SRU system, resulting in an annualized cost of $1 million/year. If the 24 hours of excess amine was used one time per year for an entire day, 50 LTD of sulfur would have resulted in 110 tons of SO_2 emissions avoided. If there are three occurrences per year where the excess amine solution is used, 330 tons of emissions would be reduced. This scenario results in a cost-effectiveness ranging from $3,000 to 9,000 per ton of SO_2 reduced.

Option 2 is to have a redundant Claus unit. The capital cost of a 50 LTD Claus unit is also approximately $10 million, resulting in an annualized cost of $1 million/year. Again, if there are one to three days of emissions avoided, this option results in a cost-effectiveness ranging from $3,000 to $9,000 per ton of SO_2 reduced. For sulfur recovery plants consisting of multiple Claus units, the likelihood of needing the additional Claus train more than three times per year increases significantly, making the redundant Claus unit a cost-effective option.

It is difficult to predict the quantity of emissions avoided as they are dependent on random malfunction events of variable durations. While the cost-effectiveness values of these options are not necessarily compelling given the uncertainty in the emissions avoided, the options evaluated are expected to be extreme measures. It is likely, for example, that maintaining appropriate spare parts for the system would provide a cost-effective means of reducing emissions. This, along with short-term reductions in high-sulfur fuel gas production could be used to eliminate the need to flare or otherwise combust these high sulfur-containing fuel gases.

Based on this analysis, we are proposing that a start-up, shutdown, and malfunction plan that specifically addresses the minimization of fuel gas combustion of high sulfur-containing fuel gases during malfunctions of an amine treatment system or sulfur recovery plant is BDT. The start-up, shutdown, and malfunction plan will address specific process upset and malfunction events associated with the amine treatment system and sulfur recovery plant and the standard operating procedures to follow to minimize emissions during these events. Compliance is demonstrated by following the procedures in the plan. As previously mentioned, we are proposing a work practice standard rather than an equipment standard to provide flexibility to the refinery owner or operator regarding the best way to minimize malfunction emissions given the refinery's specific configuration and sulfur loads.

Finally, we evaluated a requirement for performing root-cause analyses as a means to minimize the frequency of process malfunctions and thereby

reduce malfunction emissions. Even though process upset gas is exempt from the SO_2 emission limits associated with fuel gas combustion units, we believe it is good air pollution practice to investigate the causes of significant atmospheric releases caused by process upsets or malfunctions to determine if similar upsets or malfunctions can be reasonably prevented from recurring. Similarly, we believe it is good pollution control practice to investigate significant emission exceedances to determine the cause of the exceedance and to implement procedures to prevent its recurrence. The cost-effectiveness of these investigations is dependent on the frequency and magnitude of the emission episodes; for very small emission episodes, the manpower required to perform the investigations do not justify the potential emission reductions that might be realized from the root-cause analysis. We estimate that a root-cause analysis would cost approximately $2,500 to perform. For emissions of less than 500 pounds per day, the cost-effectiveness of the root-cause analysis, even assuming it would completely eliminate a future recurrence, would be approximately $10,000 per ton of SO_2 reduced. Similarly, for emissions of 1,000 pounds per day, the cost-effectiveness would be on the order of $5,000 per ton of SO_2 reduced. As the probability of successfully identifying a means to avoid future emissions from each root-cause analysis performed is certainly less than 100 percent, we determined that it was not cost effective to perform root-cause analyses for SO_2 emissions exceedances of 500 pounds per day or less and request comment on alternative thresholds in the range of 500 to 1,000 lbs per day.

For SO_2 releases of greater than 500 pounds per day, the emissions reductions potential of the root-cause analyses increases and the cost-effectiveness improves, so we are proposing that performing root-cause analyses for SO_2 releases of greater than 500 pounds per day would be BDT. Any emission limit exceedance or any process start-up, shutdown, upset or malfunction that causes a discharge into the atmosphere in excess of 500 pounds per day of SO_2 would require a root cause analysis to be performed. We also considered a similar requirement for hydrocarbon flaring events with the purpose of reducing VOC emissions. However, we expect refinery owners and operators to investigate large hydrocarbon releases as these releases represent lost revenues. Furthermore, as flares are efficient in destroying VOC, the potential to significantly reduce VOC emissions by performing root-cause analysis is much less than the potential for reducing SO_2 emissions. We request comment on the need to include root cause analyses for hydrocarbon releases. If root-cause analyses are recommended, please provide in your comments the recommended release quantities that would trigger the root-cause analysis and justification for the recommendation. If root cause analyses are not recommended, please provide in your comments the rationale for not requiring root-cause analysis for any VOC (hydrocarbon) releases.

The proposed rule is intended to provide flexibility for each refinery owner and operator to develop procedures that are efficient and effective for their process configuration. The scope of these requirements is limited to affected facilities under this rule. We request comment on the need to implement this requirement to all new process units at the refinery, not just fuel gas producing units such as fluid catalytic cracking units, fluid coking units, fuel gas combustion devices, and sulfur recovery plants.

On the other hand, based on site-specific conditions and given the nature of the types of emissions events that are being addressed by the start-up, shutdown, and malfunction plan, it is impossible to conclusively determine that one or all of the emission reduction methods addressed in the start-up, shutdown, and malfunction plan will achieve any set level of emissions reduction or that those reductions, if any, will be cost-effective. Therefore, we are co-proposing no requirement for a start-up, shutdown, and malfunction plan. We request comments and supporting data that indicate the emission reductions that could be reasonably expected from a flare minimization plan for planned start-up and shutdown events, the number of planned events that occur per year (or over a 5 year period), and any other information that can be used to justify either the inclusion or exclusion of this provision in the final rule. We also request comments and supporting data that indicate the number and duration of malfunctions in the amine stripper and sulfur recovery plants, the costs associated with alternative sulfur shedding practices, and other information that can be used to justify either the inclusion or exclusion of this provision in the final rule.

Finally, we request comment, along with supporting data, that indicate the frequency of emission events exceeding 500 pounds per day, the percentage of times the root-cause analysis results in positive steps that may avoid future recurrence of the event, and other information that can be used to justify either the inclusion or exclusion of this provision in the final rule.

Delayed Coking Unit Depressurization. The primary emission releases from delayed coking units occur as the coking vessels are depressurized and petroleum coke is removed from the unit. When the delayed coking cycle is completed, the coke-filled vessel is steam stripped. Most of the gases from this process continue to be sent to the coking unit distillation column. At some point in time, the steam gas discharge is diverted to the blow-down system. The delayed coking unit typically has a fuel gas recovery system (compressor) due to the quantity of fuel gas produced by the unit. Therefore, it is cost-effective to require the blow-down system gases to be recovered in the unit's fuel gas recovery system, in keeping with the proposed work practice standard that fuel gas from fuel gas producing units will not be routinely flared.

As the process unit continues to depressurize, there is a point where the gases can no longer be discharged to the blow-down system or fuel gas recovery line, at which point the remaining steam and gases are vented to the atmosphere. To achieve maximum reduction of uncontrolled releases, the unit should be depressurized to as low a pressure as possible before venting to the atmosphere. Below a pressure of 5 pounds per square inch gauge (psig) in the delayed coking unit drum, it is not technically feasible to divert the emissions for recovery. Above a vessel pressure of 5 psig, it is technically feasible to divert the emissions for recovery. Furthermore, as the unit already has a gas compressor, the costs associated with recovering these gases is minimal.

We estimate that this practice can reduce VOC emissions by 120 tons per year and SO_2 emissions by at 200 tons per year. The total annualized costs are expected to be minimal for new units, but installing the appropriate piping for a modified or reconstructed unit may result in annualized costs of up to $100,000 per year. Even under this extreme condition, the cost effectiveness of the requirement is about $800 per ton of VOC reduced and $500 per ton of SO_2 reduced. Therefore, we conclude that a work practice standard that requires a delayed coking unit to depressure to 5 psig during reactor vessel depressuring and vent the exhaust gases to the fuel gas system for recovery is BDT. Note this determination is independent of the

work practice to eliminate routine flaring from fuel gas producing units and requires flare gas recovery of depressurization gases even under the option of no work practice requirement to minimize flaring.

In addition to the depressurization emissions, we also identified at least one refinery that has designed an enclosed system for their coke-cutting operations. Coke cutting operations were identified as a significant VOC emission source at refineries during an Alberta Research Council study, with an estimated VOC emissions rate of 1,300 tons per year. We do not have any data regarding the effectiveness of the coke-cutting enclosure system, whether the enclosure seals are air tight or if they allow some percentage of the emissions escape. The enclosure may simply suppress the emissions until the coke is removed from the unit, at which time the emissions are released. Additionally, we do not have any data on the costs of these systems and whether or not existing units can be retrofitted if the delayed coking unit is modified or reconstructed. Therefore, we cannot conclude that an enclosed coke cutting system is BDT, but we request comment and additional information on coke-cutting system controls, their cost, their effectiveness, and their limitations.

VI. Modification and Reconstruction Provisions

Existing affected sources that are modified or reconstructed would be subject to the proposed standards in 40 CFR part 60, subpart Ja. A modification is 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 (see 40 CFR 60.14). Changes to an existing 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.

Rebuilt petroleum refinery process units would become subject to the proposed standards in 40 CFR part 60, subpart Ja 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).

With the exception of the standards for fluid catalytic cracking units, we are proposing that modified or reconstructed sources be subject to the same proposed standards in 40 CFR part 60, subpart Ja, as new sources. The decision to maintain consistent standards for both new and modified or reconstructed sources was based on an evaluation of the cost-effectiveness and incremental cost-effectiveness of the proposed standards on both types of sources and on the feasibility of retrofitting existing units. We have included in the docket a table (Impacts Summary) which summarizes our estimates costs for different control options for both new and reconstructed or modified process units. We request comment on these cost estimates and on specific issues related to the feasibility of retrofitting existing units, as well as our assessment that cost-effectiveness numbers are similar enough such that it is appropriate to have identical standards for both new and modified or reconstructed sources.

VII. Request for Comments

Table 10 summarizes the topics on which we have specifically requested comment throughout this preamble. We note, however, that comments on all aspects of this proposal are welcome.

TABLE 10.—SUMMARY OF TOPICS ON WHICH COMMENT IS REQUESTED

Topic	Section in this preamble where topic is discussed
Effects of proposed PM, SO_2 and NO_X standard on modified or reconstructed fluid catalytic cracking units. Also co-proposed 40 CFR part 60, Subpart J standards for SO_2 and PM and no NO_X limits for modified and reconstructed sources.	III.B. and V.E.1.
Exemption for emergency flares	IV.A.
Exemption from monitoring for fuel gas streams related to commercial liquid products	IV.A.
Exemption from monitoring for fuel gas streams generated by process units that are intolerant of sulfur	IV.A.
Alternative PM limit for fluid catalytic cracking units based on condensable PM as well as filterable PM	V.E.1.
Alternative lower (20 ppmv, 40 ppmv) NO_X limit, averaged over 365 days, for fluid catalytic cracking units	V.E.1.
Co-propose no new NO_X standard for fluid coking units	V.E.2.
Appropriate long-term average H_2S concentration limit for fuel gas combustion units, and requirement to monitor TRS instead of H_2S for fuel gas from coker units.	V.E.4.
Various aspects of work practice standards to minimize routine flaring and enhance SO_2 control versus no standards: alternative means of eliminating flaring, number of "fuel gas rich" refineries, need for a startup, shutdown, and malfunction plan (SSMP), including rationale for or against requiring a root cause analysis for hydrocarbon releases and sulfur shedding practices, and information about emission control systems for coke cutting operations. Also co-propose no requirements for routine flaring and no SSMP.	V.D.5.

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

In setting standards, the CAA requires us to consider alternative emission control approaches, taking into account the estimated costs as well as impacts on energy, solid waste, and other effects. We request comment on whether we have identified the appropriate alternatives and whether the proposed standards adequately take into consideration the incremental effects in terms of emission reductions, energy, and other effects of these alternatives. We will consider the available information in developing the final rule.

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

We are presenting estimates of the impacts for the proposed requirements of subpart Ja that change the performance standards: the emission limits for fluid catalytic cracking units, sulfur recovery plants, fluid coking units, fuel gas combustion devices, and process heaters, as well as the work practice standards. The proposed 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 refining process units complying with the proposed subpart Ja and the current NSPS requirements of subpart J (i.e., baseline). The impacts are presented for petroleum refining 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 proposed 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 proposed subpart Ja. Sources that are modified or reconstructed over the next 5 years would comply with subpart J in the absence of proposed subpart Ja. We assumed that prior to reconstruction or modification, these sources would either be subject to a consent decree (equivalent to about 77 percent of the industry by capacity), complying with subpart J or equivalent limits, 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 proposed subpart Ja were estimated from those starting points as well. The estimated costs presented for work practice standards include only the labor cost to prepare the required plan or analysis; we did not attempt to quantify costs and emission reductions for the variety of ways a facility may choose to implement those plans. We assumed that each facility would evaluate their options and choose the most cost-effective option for the facility's unique position. 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 proposed rule, we evaluated the cost-effectiveness of each option for new sources separately from reconstructed and modified sources. However, since our selections for each process unit and pollutant were consistent for all units, we are presenting our costs and emission reductions for the overall rule. We estimate that the proposed amendments will reduce combined emissions of PM, SO_2, and NO_X about 55,800 tons/yr from the baseline. The estimated increase in annual cost, including annualized capital costs, is about $54,100,000. The overall cost-effectiveness is about $970 per ton of pollutants removed. The estimated nationwide 5-year incremental emissions reductions and cost impacts for the proposed amendments are summarized in Table 11 of this preamble.

TABLE 11.—NATIONAL INCREMENTAL EMISSION REDUCTIONS AND COST IMPACTS FOR PETROLEUM REFINERY UNITS SUBJECT TO PROPOSED STANDARDS UNDER 40 CFR PART 60, SUBPART JA (FIFTH YEAR AFTER PROPOSAL)

Process unit	Pollutant	Total capital cost ($1,000)	Total annual cost ($1,000/yr)	Annual emission reductions (tons/yr)	Cost-effectiveness ($/ton)
FCCU	PM and SO_2	40,000	9,500	9,500	1,000
FCCU	NO_X	28,000	7,300	3,500	2,100
Fluid Coker	PM and SO_2	14,000	4,800	23,000	210
Fluid Coker	NO_X	4,500	970	760	1,300
SRP	SO_2	1,100	680	550	1,200
Process Heaters and Fuel Gas Combustion.	SO_2	0	2,880	1,300	2,200
Process Heaters	NO_X	140,000	28,000	17,000	1,600
Work Practices			250		
Total		230,000	54,000	56,000	970

B. What are the secondary impacts?

Indirect or secondary air quality impacts of this proposed rule would result from the increased electricity usage associated with the operation of control devices. Assuming that plants would purchase electricity from a power plant, we estimate that the standards as proposed would increase secondary emissions of criteria pollutants, including PM, SO_2, NO_X, and CO from power plants. For new, modified or reconstructed sources, this proposed rule would increase secondary PM emissions by 24 Mg/yr (27 tpy); secondary SO_2 emissions by about 970 Mg/yr (1,100 tpy); secondary NO_X emissions by about 480 Mg/yr (530 tpy); and secondary CO emissions by about 16 Mg/yr (17 tpy) 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 fluid coker 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 proposed rule will generate 4.5 billion gallons of water per year for the 5 years following proposal. We also estimate that this proposed rule will generate 8,600 Mg/yr (7,800 tpy) of solid waste over those 5 years.

Energy impacts consist of the electricity and steam needed to operate control devices and other equipment that would be required under the proposed 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 proposed rule would increase overall energy demand by about 170 gigawatt-hours per year (590 billion British thermal units per year).

C. What are the economic impacts?

This proposal affects certain new and reconstructed/modified sources found at petroleum refineries as defined earlier in this preamble. We performed an economic impact analysis that estimates changes in prices and output for gasoline nationally using the annual compliance costs estimated for this proposal. The methodology for this

analysis incorporates changes in producer and consumer behavior by considering passthrough of increased production costs from producers to consumers. All estimates are for the fifth year after proposal since this is the year for which the compliance cost impacts are estimated.

The analysis estimates a price increase in gasoline of less than 0.02 percent nationally will take place along with a corresponding reduction in gasoline output of less than 0.004 percent (or less than 6 million gallons a year). The overall total annual social costs, which reflect changes in consumer and producer behavior in response to the compliance costs, are $53.0 million (2005 dollars) or almost identical to the compliance costs.

For more information, please refer to the economic impact analysis report that is in the public docket for this proposed rule.

D. What are the benefits?

We estimate the monetized benefits of this proposed rule to be $957 million (2005$) in the fifth year after proposal. We base the portion of the benefits estimate derived from the $PM_{2.5}$ and SO_2 emission reductions on the approach and methodology laid out in EPA's 2004 benefits analysis supporting the regulation of emissions from the Industrial Boilers MACT (included in the Regulatory Impact Analysis (RIA) for the Industrial Boilers and Process Heaters NESHAP, February 2004). We chose the benefit analysis contained in this RIA as the basis for estimating the benefits from emission reductions of these two pollutants since most of the elements in that rule are similar to those covered here. These elements, which are the stack height, a number of the controls applied, and the pollutants affected—$PM_{2.5}$ and SO_2, but not NO_X—are similar to those covered by the Industrial Boiler MACT standard.

We base the portion of the benefits estimate derived from the NO_X emission reductions on the approach and methodology laid out in EPA's 2005 benefits analysis supporting the regulation of emissions from the Clean Air Interstate Rule (CAIR) (included in the Regulatory Impact Analysis for the Clean Air Interstate Rule, March 2005). We chose the CAIR analysis as the basis for estimating the benefits from emission reductions of this pollutant since most of the elements in CAIR are similar to those covered here. These elements, which are the stack height, a number of the controls applied, and the pollutant affected—in this case, NO_X only—are similar to those covered by CAIR. These three factors lead us to believe that we might reasonably estimate benefits for this proposed rule using a benefits transfer approach and values from the Industrial Boilers MACT analysis for estimating the SO_2 and $PM_{2.5}$ benefits of this rule, and the CAIR analysis for the NO_X benefits of the rule. Specifically, these estimates are based on application of the benefits scaling approach derived from the benefits analyses completed for these rulemakings. As mentioned above, the methodologies are laid out in the Industrial Boilers MACT and CAIR RIA. A summary of the benefits estimates is in Table 12 below.[1]

TABLE 12.—SUMMARY OF BENEFITS ESTIMATES FOR PROPOSED NSPS

Pollutant	Monetized benefits per ton emission reduction	Emission reductions (tons)	Total monetized benefits* (millions of 2005 dollars)
$PM_{2.5}$	$88,000	3,221	$283.4
SO_2	20,000	31,358	627.2
NO_X	2,200	21,266	46.8
Grand Total:	.....	.....	$957.4

* All estimates are for the analysis year (fifth year after proposal). Emission reductions reflect the combination of proposed options for both new and reconstructed/modified sources.

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 American Cancer Society cohort (ACS) (Pope, C.A. III, et al., ''Lung Cancer, Cardiopulmonary Mortality, and Long-Term Exposure to Fine Particulate Air Pollution,'' JAMA, 2002). Since the publication of CAIR, the EPA's Office of Air and Radiation has adopted a different format for its benefits analysis in which characterization of the uncertainty in the concentration response function is integrated into the main benefits analysis. The 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 recently completed expert elicitation study. Specifically, compared to the final PM NAAQS estimate of the mean mortality from the ACS cohort, the expert-based premature mortality incidence ranged from 50 percent of the mean ACS estimate to more than five times the size of the ACS mean estimate. The Agency is currently updating the estimates used here to calculate the benefits of the proposed NSPS and intends to consider using these updated benefits estimates as part of an approach similar to that used in the PM NAAQS RIA in the benefits analyses for the final NSPS.

With the annualized costs of this rulemaking estimated at $54 million (2005$) in the fifth year after proposal and with estimated benefits of $957 million (2005$) for that same year, 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. For more information, please refer to the RIA for this proposed rule that is available in the docket.

IX. 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

[1] We use the SO_2 benefits/ton estimate derived from the Industrial Boilers MACT benefit analysis based on the factors listed above. We also note that the SO_2 benefits/ton estimate derived from the CAIR benefits analysis is $18,000 in 2010 and $22,000 in 2015, both of which are quite close to the estimate we use in this analysis. We use the NO_X benefits/ton estimate from the CAIR Boilers MACT benefits analysis (no NO_X reductions take place as a result of the Industrial Boilers MACT).

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 Regulatory Impact Analysis (RIA) for the Proposed Petroleum Refinery NSPS, EPA–452/R–07–006. 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 at $957 million (2005 dollars), and the annualized costs of this action are estimated at $54 million (2005 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 proposed amendments to the existing standards of performance for petroleum refineries would add a monitoring exemption for fuel gas streams combusted in a fuel gas combustion device that are inherently low in sulfur content. The exemption would apply 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 would 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 would occur as a result of the exemption would not be 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. The 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 1054.07.

A copy of the OMB-approved ICR for the Standards of Performance for Petroleum Refineries may be obtained from Susan Auby, Collection Strategies Division, Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW., Washington, DC 20460, by e-mail at *auby.susan@epa.gov,* or by calling (292) 566–1672.

The information collection requirements in the proposed 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 ICR document prepared by EPA has been assigned EPA ICR number 2263.01.

The proposed standards of performance for petroleum refineries include work practice requirements for delayed coking reactor vessel depressuring and written plans to minimize emissions during startups, shutdowns, and malfunctions. Plants also would be required to analyze the cause of any exceedance that releases more than 500 pounds per day of SO_2 above an allowable limit. EPA is co-proposing work practice standards that would include the requirement for delayed coking reactor vessel depressuring but exclude the requirements for written plans and root-cause analyses for SO_2 emissions discharges exceeding allowable limits by at least 500 pounds per day. The proposed standards also include testing, monitoring, recordkeeping, and reporting provisions. Monitoring requirements may include control device operating parameters, bag leak detection systems, or CEMS, depending on the type of process, pollutant, and control device. Exemptions are also proposed for small emitters. 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 annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 6,084 labor-hours per year at a cost of $526,241 per year. The annualized capital costs are estimated at $2,736,000 per year and operation and maintenance costs are estimated at $1,627,200 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 VIII.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 proposed subpart Ja.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

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.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques, EPA has established a public docket for this rule, which includes this ICR, under Docket ID number EPA–HQ–OAR–2007–0011. Submit any comments related to the ICR for this proposed rule to EPA and OMB. See **ADDRESSES** section at the beginning of this document for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, *Attention:* Desk Office for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after May 14, 2007, a comment to OMB is best assured of having its full effect if OMB receives it by June 13, 2007. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

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 today's proposed action on small entities, small entity is defined as: (1) A small business whose parent company has no more than 1,500 employees and no more than 125,000 barrels per day total operable atmospheric crude oil distillation capacity, 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 today's proposed action on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Of the 58 entities that we expect could be affected by today's proposed action, 24 of these (or 41 percent) are classified as small according to the SBA small business size standard listed previously. Of these 24 affected entities, one small entity is expected to incur an annualized compliance cost of more than 1.0 percent to comply with today's proposed action. In addition, the impact on gasoline prices nationwide is expected to be less than 0.02 percent of the baseline gasoline price, and this represents less than a 1 cent increase in the price per gallon of gasoline. Also, the output of gasoline in the U.S. is expected to fall by less than 0.004 percent, or less than 6 million gallons per year in the U.S. For more information, please refer to the economic impact analysis that is in the public docket for this rulemaking.

Although this proposed action would not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this proposed 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. We continue to be interested in the potential impacts of this proposed action on small entities and welcome comments on issues related to such impacts.

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 1 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 proposed 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 1 year. As discussed earlier in this preamble, the estimated expenditures for the private sector in the fifth year after proposal are $54 million. Thus, this proposed action is not subject to the requirements of section 202 and 205 of the UMRA. In addition, EPA has determined that this proposed action contains no regulatory requirements that might significantly or uniquely affect small governments. This proposed 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 1 year or any disproportionate impacts on them. Therefore, this proposed 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 proposed 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 proposed action.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed action from State and local officials.

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

Executive Order 13175, entitled (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 proposed 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 proposed rules impose requirements on owners and operators of specified

industrial facilities and not tribal governments. Thus, Executive Order 13175 does not apply to this proposed action.

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

Executive Order 13045 ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

EPA interprets Executive Order 13045 as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This proposed action is not subject to Executive Order 13045 because it is based on technology performance and not on health or safety risks.

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 economic impact analysis for today's proposed action. Our analysis shows that there is a reduction in gasoline output of less than 6 million gallons per year, or less than 400 barrels of gasoline production per day, in the fifth year after proposal of this proposed action. In addition, our analysis shows that there is an increase in gasoline prices of less than 0.02 percent in the fifth year after proposal of this proposed action. Given this degree of increase in domestic gasoline prices, no significant increase in our dependence on foreign energy supplies should take place. Finally, today's proposed action will have no adverse effect on crude oil supply, coal production, electricity production, and energy distribution. Based on the findings from the analysis of impacts on energy markets, we conclude that today's proposed action is not a ''significant energy action'' as defined in Executive Order 13211. For more information on this analysis, please refer to the economic impact analysis for this rulemaking. This analysis is found in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Public Law No. 104–113, Section 12(d), 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. The VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency does not use available and applicable VCS.

Today's proposed rule (subpart Ja) involves technical standards. The EPA cites the following standards: EPA Methods 1, 2, 3, 3A, 3B, 5, 6, 6A, 6B, 6C, 7, 7A, 7C, 7D, 7E, 10, 10A, 11, 15, 15A, and 16 of 40 CFR part 60, appendix A; Performance Specifications 2, 3, 4, 5, 7, and 11 in 40 CFR part 60, appendix B; and Appendix F to 40 CFR Part 60. This rule also cites ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' for its manual methods of measuring the content of the exhaust gas. This part of ASME PTC 19.10–1981 is an acceptable alternative to EPA Methods 3B, 6, 6A, 6B, 7, 7C, and 15A.

Consistent with the NTTAA, EPA conducted searches to identify VCS in addition to these methods. No applicable VCS were identified for EPA Methods 7D and 11; EPA Performance Specifications 3, 4, 5, and 7; and Appendix F to 40 CFR part 60. The search and review results are in the docket for this rule.

The search for emissions measurement procedures identified 22 other VCS. The EPA determined that these 22 standards identified for measuring emissions of the targeted pollutants or surrogates subject to emission standards in this rule were impractical alternatives to EPA test methods for the purposes of this rule. Therefore, EPA does not intend to adopt these standards for this purpose. The reasons for the determinations for the 22 standards are discussed in the memorandum submitted to the docket to this rule.

Both the proposed amendments for subpart J and the proposed rule (subpart Ja) cite the Gas Processor's Association Method 2377–86, ''Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes'' (incorporated by reference-see 40 CFR 60.17) as an acceptable method for determining the H2S content of low sulfur streams. The amendments to subpart J do not include any other technical standards.

Consistent with the NTTAA, EPA conducted searches to identify VCS in addition to Gas Processor's Association Method 2377–86. No applicable voluntary consensus standards were identified for Gas Processor's Association Method 2377–86. The search and review results are in the docket for this rule.

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 proposed 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 (Feb. 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 the proposed amendments would 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 proposed 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. EPA has determined that the proposed standards would not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because they would increase the level of

environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. These proposed standards would reduce emissions of criteria pollutants from all new, reconstructed, or modified sources at petroleum refineries, decreasing the amount of such emissions to which all affected populations are exposed.

List of Subjects in 40 CFR Part 60

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

Dated: April 30, 2007.

Stephen L. Johnson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I of the Code of Federal Regulations is proposed to be 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 Tables 1 and 3 of subpart EEEE, Tables 2 and 4 of subpart FFFF, § 60.106(e)(2) of subpart J, §§ 60.104a(d)(3), (d)(6), (g)(3), (g)(4), (g)(6), (i)(3), (i)(4), (j)(3), (j)(4), (j)(4)(iii), and 60.105a(d)(4), (e)(4), (f)(2), and (f)(4), and 60.106a(a)(1)(ii), (a)(1)(iv), (a)(2)(ii), (a)(2)(iv), (a)(3)(ii), (a)(3)(iv), and (a)(4)(iii), and 60.107a(a)(1)(ii), (a)(1)(iv), (a)(2)(ii), (c)(2), and (c)(4) of subpart Ja, 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 Method 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, 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 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 which commences construction, reconstruction, or modification after June 11, 1973, and on or before May 14, 2007, 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 paragraphs (d), (i), (j), and (k) 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.

* * * * *

(i) *Claus sulfur recovery plant* means a series of process units which recover sulfur from hydrogen sulfide (H_2S) by a vapor-phase catalytic reaction of sulfur dioxide and H_2S. The *Claus sulfur recovery plant* includes the reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems. One *Claus sulfur recovery plant* may consist of multiple trains.

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

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

* * * * *

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, 0 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 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) Gas streams that meet commercial-grade product specifications and have a sulfur content of 30 ppmv or less.

(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, and the isomerization unit.

(D) Other 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 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 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 gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the 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 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 gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested gas stream/system demonstrating that the sulfur content is less than 5 ppmv. Minimum sampling data must consist of 2 weeks of daily monitoring (14 grab samples) for frequently operated gas streams/systems; for infrequently operated 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 Processor Association's Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, 1986 revision with ranges 0–10/0–100 ppm (N = 10/1) to test the applicant stream (incorporated by reference—see § 60.17).

(v) A description of how the 2 weeks (or seven samples for infrequently operated gas streams/systems) of monitoring results compares to the typical range of H_2S concentration (fuel quality) expected for the 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 gas stream going to the loading rack flare).

(2) Once EPA receives a complete application, the Administrator will determine whether an exemption is granted. The owner or operator shall continue to comply with the monitoring requirements in paragraph (a)(3) or paragraph (a)(4) of this section until an exemption is granted.

(3) Once an exemption from continuous monitoring is granted, no further action is required unless refinery operating conditions change in such a way that affects the exempt 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)(2)(i), (b)(2)(ii), or (b)(2)(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 a new application 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 a new application, the owner or operator must begin continuous monitoring as specified in paragraphs (a)(3) or (a)(4) of this section within 60 days of 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 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 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 stream, the owner or operator shall maintain records of the specific exemption chosen for each 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. Section 60.109 is amended by redesignating paragraph (b)(2) as (b)(3) and adding paragraph (b)(2) to read as follows:

§ 60.109 Delegation of authority.

* * * * *

(b) * * *

(1) * * *

(2) Section 60.105(b), and

* * * * *

12. 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.
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, delayed coking units, process heaters, other fuel gas combustion devices, fuel gas producing units, 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) 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.

(c) 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 coking units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors.

Flexicoking unit means one or more coking units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced then gasified to produce a synthetic fuel gas.

Fluid catalytic cracking unit means one or more units 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.

Fluid coking unit means one or more coking units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system and in which the fluid coking burner exhaust gas is continuously released to the atmosphere. The *fluid coking unit* includes equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent. Flexicoking units that use gasifiers to generate a synthetic fuel gas for use in other processes and that do not exhaust to the atmosphere are not considered *fluid coking units* under this subpart.

Fresh feed means any petroleum derivative feedstock stream charged directly into the riser or reactor of a FCCU except for petroleum derivatives recycled within the FCCU, fractionator, or gas recovery unit.

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 producing unit means any refinery process unit that produces fuel gas as a routine part of normal operations. A *fuel gas producing unit* includes, but is not limited to, the atmospheric distillation unit, the FCCU, the catalytic hydrocracking unit, all types of coking units, and the catalytic reforming unit.

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

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.

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 gas means any gas generated by a petroleum refinery process unit, except fuel gas and process upset gas as defined in this section.

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 recycling the H_2S to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant.

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

Sulfur recovery plant means all process units which recover sulfur from H_2S and/or SO_2 at a petroleum refinery. The *sulfur recovery plant* also includes vessels, tanks, or pits used to store the recovered sulfur product. 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.

§ 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.

Option 1 for Paragraph (b):

(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 fluid coking unit:

(1) Particulate matter (PM) in excess of 0.5 gram per kilogram (g/kg) coke burn-off (0.5 pound (lb) PM/1,000 lbs coke burn-off) or 0.020 grains per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air; and

(2) 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; and

(3) 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; and

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

Option 2 for Paragraph (b)

(b) Except as provided in paragraph (b)(2) of this section, 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 fluid coking unit:

(1) Particulate Matter (PM) in excess of 0.5 gram per kilogram (g/kg) coke burn-off (0.5 lb PM/1,000 lbs coke burn-off) or 0.020 grains per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air; and

(2) 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. This emissions limit does not apply to a fluid coking unit subject to this subpart;

(3) 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; and

(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 fluid coking unit that uses continuous parameter monitoring systems (CPMS) according to § 60.105a(b)(1) shall comply with the applicable control device parameter operating limit in paragraph (c)(1) or (c)(2) of this section.

(1) If the FCCU or fluid coking unit is controlled using an electrostatic precipitator:

(i) The hourly average total power and secondary current to the control device must not fall below the level established during the most recent performance test; and

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

(2) If the FCCU or fluid coking unit is controlled using a wet scrubber:

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

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

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

(1) For a FCCU or fluid coking unit with no post-combustion control device:

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

(2) For a FCCU or fluid coking unit 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.

(e) Each owner or operator that is subject to the provisions of this subpart shall comply with the following emissions limits for each sulfur recovery plant:

(1) For a sulfur recovery plant with a capacity greater than 20 long tons per day (LTD), the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing a combined SO_2 and reduced sulfur compounds concentration in excess of 250 ppmv as SO_2 (dry basis) at 0 percent excess air determined hourly on a 12-hour rolling average basis. 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.

(2) For a sulfur recovery plant with a capacity of 20 LTD or less, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing combined SO_2 and reduced sulfur compounds mass emissions in excess of 1 percent by weight of sulfur recovered, measured as the mass ratio of sulfur emitted (from all release points combined) to sulfur recovered determined hourly on a 12-hour rolling average basis.

(3) For all sulfur recovery plants, regardless of size, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing H_2S in excess of 10 ppmv (dry basis) at 0 percent excess air determined hourly on a 12-hour rolling average basis.

(f) The owner or operator of a sulfur recovery plant subject to the H_2S emissions limit in paragraph (e)(3) of this section and that uses CPMS pursuant to § 60.106a(a)(4) shall comply with the following operating limits:

(1) The hourly average temperature of the exhaust gases exiting the sulfur recovery plant must not fall below the level established during the most recent performance test.

(2) The hourly average O_2 concentration of the exhaust gases exiting the sulfur recovery plant must not fall below the level established during the most recent performance test.

(g) Each owner or operator subject to the provisions of this subpart shall comply with the emission limitations in paragraphs (g)(1) through (3) for each process heater and other fuel gas combustion device, except as provided in paragraph (h) and (i) of this section.

(1) SO_2 in excess of 20 ppmv (dry basis, corrected to 0 percent excess air) on a 3-hour rolling average basis; and

(2) 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; and

(3) For process heaters with a rated capacity of greater than 20 million British thermal units per hour, NO_X in excess of 80 ppmv (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis.

(h) For process heaters that combust only fuel gas and for other fuel gas combustion devices, the following emission limitations may be used instead of the SO_2 emission limits in paragraph (g)(1) and (2) of this section:

(1) For process heaters and other fuel gas combustion devices that do not combust fuel gas generated from a coking unit:

(i) H_2S in excess of 160 ppmv determined hourly on a 3-hour rolling average basis; and

(ii) H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(2) For process heaters and other fuel gas combustion devices that combust fuel gas generated from a coking unit or fuel gas that is mixed with fuel gas generated from a coking unit:

(i) Total reduced sulfur (TRS) in excess of 160 ppmv determined hourly on a 3-hour rolling average basis; and

(ii) TRS in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(i) 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 paragraphs (g) and (h) of this section.

Option 1 for § 60.103a:

§ 60.103a Work practice standards.

(a) Each owner or operator subject to the provisions of this subpart shall not routinely release fuel gas to a flare from any fuel gas producing unit. The combustion in a flare of process upset gases or fuel that that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

(b) The owner or operator shall develop a written startup, shutdown, and malfunction plan that describes, in detail, procedures for operating and maintaining each affected facility during periods of startup, shutdown, and malfunction; and a program of corrective action for malfunctioning process, air pollution control, and monitoring equipment used to comply with the requirements of this subpart. The owner or operator may use the affected source's standard operating procedures (SOP) manual, or an Occupational Safety and Health Administration (OSHA) or other plan, provided the alternative plans meet all the requirements of this section and are made available for inspection or submitted when requested by the Administrator.

(1) The written plan must cover fluid catalytic cracking units, fluid coking units, sulfur recovery plants (including tail gas treatment system), amine treatment system, and fuel process heaters and other gas combustion devices. The written plan must include procedures to minimize discharges either directly to the atmosphere or to the flare gas system during the planned startup or shutdown of these units, procedures to minimize emissions during malfunctions of the amine treatment system or sulfur recovery plant, and procedures for conducting 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 refinery process unit subject to the provisions of this subpart in excess of 500 lb per day (lb/d) of SO_2.

(2) When actions taken by the owner or operator during a startup or shutdown (and the startup or shutdown causes the source to exceed any applicable emission limitation in the relevant emission standards), or malfunction (including actions taken to correct a malfunction) are consistent with the procedures specified in the startup, shutdown, and malfunction plan, the owner or operator must keep records for that event which demonstrate that the procedures specified in the plan were followed. These records may take the form of a ''checklist,'' or other effective form of recordkeeping that confirms conformance with the startup, shutdown, and malfunction plan and describes the actions taken for that event. The owner or operator must identify the exceedance in the semiannual excess emissions report and certify that the actions taken during the startup, shutdown, or malfunction were consistent with the procedures in the startup, shutdown, and malfunction plan.

(3) If an action taken by the owner or operator during a startup, shutdown, or malfunction (including an action taken to correct a malfunction) is not consistent with the procedures specified in the startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation, then the owner or operator must record the actions taken for that event and identify the exceedance in the semiannual excess emissions report.

(4) The owner or operator must maintain at the affected facility a current startup, shutdown, and malfunction plan and must make the plan available to the Administrator upon request.

(5) The Administrator may require the owner or operator to make changes to the startup, shutdown, and malfunction plan if the Administrator finds:

(i) The plan does not address a startup, shutdown, or malfunction event that has occurred;

(ii) The plan fails to provide for the minimization of emissions during operation of the source (including associated air pollution control and monitoring equipment) during a startup, shutdown, or malfunction event;

(iii) The plan does not provide adequate procedures for correcting malfunctioning process and/or air pollution control and monitoring equipment as quickly as practicable; or

(6) The owner or operator may periodically revise the startup, shutdown, and malfunction plan as necessary to satisfy the requirements of this subpart or to reflect changes in equipment or procedures at the affected facility. However, each such revision to a startup, shutdown, and malfunction plan must be reported in the semiannual report.

(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 recovery.

Option 2 for § 60.103a:

§ 60.103a Work practice standards.

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 recovery.

§ 60.104a Performance tests.

(a) The owner or operator shall conduct a performance test for a FCCU, fluid coking unit, sulfur recovery plant, process heater and other 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 as provided in § 60.105a(l).

(b) The owner or operator of a FCCU or fluid coking unit that elects to monitor control device operating parameters according to the requirements in § 60.105a(b) shall conduct a PM performance test at least once every 24 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, appendix A 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 fluid coking units using the following methods and procedures:

(1) Method 1 for sample and velocity traverses.

(2) Method 2 for velocity and volumetric flow rate.

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

(4) Method 5 for determining PM emissions and associated moisture content from affected facilities.

(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 1 of this section:

$$E_{PM} = \frac{C_{PM}\ Q_{sd}}{K\ R_c} \qquad \text{(Eq. 1)}$$

Where:

E = Emission rate of PM (EPM), 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 2 of this section:

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

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-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)];

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

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

(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.

(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 3 of this section:

$$Q_r = \frac{79 \times Q_a + \left(100 - \%Oxy\right) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. 3)}$$

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 7, 7A, 7C, 7D, or 7E 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.

(6) Method 6, 6A, or 6C 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 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.

(7) Method 10, 10a, or 10B 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 4 of this section:

$$C_{adj} = C_{meas}\left[20.9_c / \left(20.9 - \%O_2\right)\right] \qquad \text{(Eq. 4)}$$

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 fluid coking unit that is controlled by an electrostatic precipitator or wet scrubber and that is subject to control device operating parameter limits § 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 operating limit for each required parameter as the lowest hourly average voltage and secondary current and the highest coke burn-off rate (if you use an electrostatic precipitator) or the lowest average pressure drop and liquid-to-gas ratio (if you use a wet scrubber) measured during a test run that achieves the applicable PM emission limit.

(f) The owner or operator of a FCCU or fluid coking unit that is exempt from the requirement to install and operate a CO CEMS pursuant to § 60.105a(g)(3) and that is subject to control device operating parameter limits in § 60.102a(d) shall establish the limits based on the performance test results using the following procedures:

(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 lowest hourly average temperature and O_2 concentration measured during a test run achieving the emission limitation.

(g) The owner or operator shall determine compliance with the SO_2 and H_2S emissions limits for sulfur recovery plants in § 60.102a(e) using the following methods and procedures:

(1) Method 1 for sample and velocity traverses.

(2) Method 2 for velocity and volumetric flow rate.

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

(4) Method 6, 6A, or 6C to determine the SO_2 concentration. The method 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.

(5) Method 15 or 15A to determine the reduced sulfur compounds and H_2S concentrations.

(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 4 of this section to adjust pollutant concentrations to 0 percent O_2 or 0 percent excess air.

(6) The owner or operator shall calculate the combined SO_2 and reduced sulfur compound concentrations for a sulfur recovery plant with a capacity greater than 20 LTD that is subject to the emissions limit in § 60.102a(e)(1) using Equation 5 of this section:

$$C_{combined} = C_{SO2,M6} + C_{SO2_eq,M15} \qquad \text{(Eq. 5)}$$

Where:

$C_{combined}$ = Cmbined SO_2 and reduced sulfur compounds concentration, ppmv, dry basis, at 0 percent excess air;

$C_{SO2,M6}$ = SO_2 concentration in the exhaust stream measured using Method 6, 6A, or 6C as required in paragraph (c)(4) of this section, ppmv, dry basis at 0 percent excess air; The method 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.

$C_{SO2_eq,M15}$ = SO_2 equivalent concentration of reduced sulfur compounds in the exhaust stream measured using Method 15 or 15A as required in paragraph (c)(5) of this section, ppmv, dry basis at 0 percent excess air. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A.

(7) The owner or operator shall calculate the mass sulfur emission percentage for a sulfur recovery plant with a capacity of 10 LTD or less that is subject to the emissions limit in § 60.102a(e)(2) using the following procedures:

(i) Calculate the combined SO_2 and reduced sulfur compound concentration using Equation 5 of this section.

(ii) Calculate the mass sulfur emissions percentage using Equation 6 of this section:

$$F_{S,emit} = \frac{K_4 \; C_{combined} \; Q_{sd}}{M_{sulfur}} \times 100\% \qquad \text{(Eq. 6)}$$

Where:

$F_{S,emit}$ = Mass fraction of sulfur emitted, weight percent;

K_4 = Conversion factor, 0.5 [lbs S/lb SO_2] × 60 [min/hr] × 1.66E–7 [lbs/dscf per ppmv]/2,240 [lbs/long ton] = 2.22E–9 (lbs S·min·long ton·lbs/dscf)/(lbs SO_2·hr·lb·ppmv);

$C_{combined}$ = Combined SO_2 and reduced sulfur compounds concentration, ppmv, dry basis at 0 percent excess air;

Q_{sd} = Volumetric flow rate of effluent gas dscf/min; and

M_{sulfur} = Mass rate of sulfur recovery, long tons/hr.

(h) The owner or operator of a sulfur recovery plant that is subject to the operating limits in § 60.102a(f) shall establish the limits based on the results of the performance test according to the following procedures:

(1) Reduce the temperature and O_2 concentrations from the CPMS to hourly averages for each test run;

(2) Determine the operating limit for temperature and O_2 concentrations as the lowest hourly average temperature and O_2 concentration measured during a test run achieving the H_2S emissions limit.

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

(1) Method 1 for sample and velocity traverses;

(2) Method 2 for velocity and volumetric flow rate;

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

(4) Method 6, 6A, or 6C to determine the SO_2 concentration. The method 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.

(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)(2)(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 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.

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

(1) Method 1 for sample and velocity traverses;

(2) Method 2 for velocity and volumetric flow rate;

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

(4) Method 11, 15, 15A, or 16 for determining the H_2S concentration for affected plants using an H_2S monitor as specified in § 60.107a(a)(1) or Method 16 for determining the TRS concentration. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A.

(i) For Method 11, 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 constitute 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 or 16, at least three injects over a 1-hour period constitutes a run.

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

(iv) If monitoring is conducted at a single point in a common source of fuel gas as allowed under § 60.107a(a)(1)(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.

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

(b) *Control device operating parameters.* Each owner or operator of a FCCU or fluid coking unit subject to the PM 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 control device.

(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.

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

(2) 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 (40 CFR part 60, appendix B).

(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. The owner or operator shall use Method 3 for conducting the relative accuracy evaluations.

(iii) The owner or operator shall comply with the quality assurance requirements of procedure 1 in 40 CFR part 60, appendix F, including quarterly accuracy determinations for CO_2 and CO monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

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

(c) *Bag leak detection systems.* Each owner or operator of a FCCU or fluid coking unit shall install, operate, and maintain a bag leak detection system for each baghouse that is used to comply with the PM emissions limit in § 60.102a(b)(1) 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 corrective 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) Corrective action 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 corrective action(s) are necessary. Corrective 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).* The owner or operator of a FCCU or fluid coking unit subject to the PM emissions limit (gr/dscf) in § 60.102a(b)(1) 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 40 CFR part 60, appendix B. 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. The owner or operator shall use Method 5 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 40 CFR part 60, appendix B. The span value of this O_2 monitor is 25 percent.

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

(5) The owner or operator shall comply with the quality assurance requirements of procedure 2 in 40 CFR part 60, appendix F for each PM CEMS and procedure 1 in 40 CFR part 60, appendix F 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) *FCCU and fluid coking units subject to NO_X limit.* Each owner or operator of a FCCU or fluid coking unit subject to the NO_X emissions limit in § 60.102a(b)(2) 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 (40 CFR part 60,

appendix B). 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. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E (40 CFR part 60, appendix A) 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 40 CFR part 60, appendix B. The span value of this O_2 monitor is 25 percent.

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

(5) The owner or operator shall comply with the quality assurance requirements of procedure 1 in 40 CFR part 60, appendix F 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.

(f) *FCCU and fluid coking units subject to SO_2 limit.* The owner or operator a FCCU and fluid coking unit subject to the SO_2 emissions limit in § 60.102a(b)(3) 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 (40 CFR part 60, appendix B). 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. The owner or operator shall use Methods 6, 6A, or 6C (40 CFR part 60, appendix A) for conducting the relative accuracy evaluations. The method 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.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of 40 CFR part 60, appendix B. The span value of this O_2 monitor is 10 percent.

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

(5) The owner or operator shall comply with the quality assurance requirements of procedure 1 in 40 CFR part 60, appendix F 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.

(g) *FCCU and fluid coking units subject to CO emissions limit.* Except as specified in paragraph (g)(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 fluid coking unit 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 (40 CFR part 60, appendix B). 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 (40 CFR part 60, appendix A). The owner or operator shall use Methods 10, 10A, or 10B for conducting the relative accuracy evaluations using the procedures specified in § 60.106a(b).

(3) A CO CEMS need not be installed if the owner or operator demonstrates that the average CO emissions are less than 50 ppm (dry basis) and also submits a written request for exemption to the Administrator and receives such an exemption.

(i) The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that meets the requirements of Performance Specification 4 (40 CFR part 60, appendix B). 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 and employ the sample conditioning system of Method 10A, the alternative relative accuracy test procedure in section 10.1 of Performance Specification 2 may be used in place of the relative accuracy test.

(ii) The written request for exemption must include descriptions of the CPMS for exhaust gas temperature and O_2 monitor required in paragraph (g)(4) of this section and operating limits for those parameters to ensure combustion conditions remain similar to those that exist during the demonstration period.

(4) The owner or operator of a FCCU or fluid coking unit that is exempted from the requirement to install and operate a CO CEMS in paragraph (g)(3) of this section shall install, operate, calibrate, and maintain CPMS to measure and record the operating parameters in paragraph (g)(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 fluid coking unit 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 fluid coking unit with a post-combustion control device, the temperature and O_2 concentration of the exhaust gas stream exiting the control device.

(h) *Excess emissions.* For the purpose of reports required by § 60.7(c), periods of excess emissions for a FCCU or fluid coking unit subject to the emissions limitations in § 60.102a(b) are defined as specified in paragraphs (h)(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 24-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. Alternatively, 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(a)(2) exceeds 0.020 gr/dscf.

(2) All rolling 7-day periods during which the average concentration of NO_X

as measured by the NO_X CEMS under § 60.105a(e) exceeds 80 ppmv.

(3) All rolling 7-day periods during which the average concentration of SO_2 as measured by the SO_2 CEMS under § 60.105a(f) 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.

(4) All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under § 60.105a(g) 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(g)(4) fall below the operating limits established during the performance test.

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

(a) *Sulfur recovery plants*. The owner or operator of a sulfur recovery plant shall comply with the applicable requirements in paragraphs (a)(1) through (5) of this section.

(1) The owner or operator of a sulfur recovery plant with a capacity greater than 20 LTD that is subject to an SO_2 emissions limit in § 60.102a(e)(1) shall install, operate, calibrate, 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 owner or operator shall install, operate, and maintain each SO_2 CEMS according to Performance Specification 2 (40 CFR part 60, appendix B). The span value for this monitor is 500 ppm SO_2.

(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 2 (40 CFR part 60, appendix B). The owner or operator shall use Methods 6 or 6C and 15 or 15A (40 CFR part 60, appendix A) for conducting the relative accuracy evaluations. The method 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 15A.

(iii) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 (40 CFR part 60, appendix B). The span value for the O_2 monitor is 25 percent O_2.

(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. The owner or operator shall use Methods 3, 3A, or 3B for conducting the relative accuracy evaluations. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference-see § 60.17) is an acceptable alternative to EPA Method 3B.

(v) The owner or operator shall comply with the applicable quality assurance procedures of 40 CFR part 60, appendix F 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.

(2) The owner or operator of a sulfur recovery plant with a capacity of less than 20 LTD that is subject to an SO_2 emissions limit in § 60.102a(e)(2) shall install, operate, calibrate, 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 of the total resultant SO_2 and an instrument for continuously monitoring the volumetric flow rate of gases released to the atmosphere. The SO_2 monitor must include an O_2 monitor for correcting the data for excess O_2.

(i) The owner or operator shall install, operate, and maintain each SO_2 monitor according to Performance Specification 2 (40 CFR part 60, appendix B). The span value for the SO_2 monitor shall be set at 125 percent of the maximum estimated hourly potential SO_2 emission concentration that translates to the applicable emission limit at full sulfur production capacity.

(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 (40 CFR part 60, appendix B). Methods 6, 6A, 6C, 15, or 15A (40 CFR part 60, appendix A) shall be used for conducting the relative accuracy evaluations. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference-see § 60.17) is an acceptable alternative to EPA Method 6, 6A, or 15A.

(iii) The owner or operator shall install, operate, and maintain each O_2 monitor and flow monitor according to Performance Specification 3 (40 CFR part 60, appendix B). The span value for the O_2 monitor is 25 percent O_2. The span value for the volumetric flow monitor shall be set at 125 percent of the maximum estimated volumetric flow rate when the unit is operating at full process capacity.

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

(v) The owner or operator shall comply with the applicable quality assurance requirements in 40 CFR part 60, appendix F for each monitor, including quarterly accuracy determinations for SO_2 and flow monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(3) Except as provided under paragraph (a)(4) of this section, the owner or operator of a sulfur recovery plant that is subject to the H_2S emissions limit in § 60.102a(e)(3) shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of H_2S (dry basis, 0 percent excess air) emissions into the atmosphere. The H_2S monitor must include an O_2 monitor for correcting the data for excess O_2.

(i) The owner or operator shall install, operate, and maintain each H_2S monitor according to Performance Specification 7 (40 CFR part 60, appendix B). The span value for this instrument is 20 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 (40 CFR part 60, appendix B). The owner or operator shall use Method 11, 15, 15A, or 16 (40 CFR part 60, appendix A) for conducting the relative accuracy evaluations. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A.

(iii) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of 40 CFR part 60, appendix B. The span value of this O_2 monitor is 25 percent.

(iv) 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. Method 3,

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

(v) The owner or operator shall comply with the quality assurance requirements of procedure 1 in 40 CFR part 60, appendix F for each monitor, including quarterly accuracy determinations and daily calibration drift tests.

(4) In place of the H_2S monitor required in paragraph (a)(3) of this section, the owner or operator of a sulfur recovery plant that is subject to the H_2S emissions limit in § 60.102a(e)(3) and that is equipped with an oxidation control system, incinerator, thermal oxidizer, or similar combustion device can use a CPMS for continuously monitoring and recording the temperature of the exhaust gases and an O_2 monitor for continuously monitoring and recording the O_2 concentration of the exhaust gases.

(i) The span values for the temperature monitor is 1,500 °F.

(ii) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 (40 CFR part 60, appendix B). The span value for the O_2 monitor is 25 percent O_2.

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

(iv) The owner or operator shall comply with the applicable quality assurance procedures in 40 CFR part 60, appendix F for each O_2 monitor, including annual accuracy determinations.

(5) The owner or operator of a sulfur recovery plant subject to an emissions limit in § 60.102a(b) shall determine and record the hourly sulfur production rate and hours of operation for each sulfur recovery plant.

(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(b) 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 3-hour average as the arithmetic average of three contiguous 1-hour averages.

(1) For sulfur recovery plants with a capacity greater than 20 LTD, all 12-hour periods during which the average concentration of SO_2 and reduced sulfur compounds as measured by the SO_2 continuous monitoring system under paragraph (a)(1) of this section exceeds 250 ppmv (dry basis, 0 percent excess air).

(2) For sulfur recovery plants with a capacity of 20 LTD or less, all 12-hour periods during which the mass rate of SO_2 and reduced sulfur compounds as measured by the continuous monitoring systems under paragraph (a)(2) of this section exceeds 1 percent of sulfur recovered.

(3) All 1-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under paragraph (a)(3) of this section exceeds 10 ppm (dry basis, 0 percent excess air) or, if applicable, all 1-hour periods during which the average temperature and O_2 concentration as measured by the continuous monitoring systems under paragraph (a)(4) of this section fall below the operating limits established during the performance test.

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

(a) *Process heaters and other fuel gas combustion devices subject to SO_2, H_2S, or TRS limit.* The owner or operator of a process heater or other fuel gas combustion device that is subject to the requirements in § 60.102(a)(g) shall comply with the requirements in paragraph (a)(1) of this section for SO_2 emissions. Alternatively, the owner or operator of a process heater or other fuel gas combustion device who elects to satisfy the requirements of § 60.102(a)(h) shall comply with the requirements in paragraph (a)(2) of this section for H_2S concentration limits or paragraph (a)(3) of this section for TRS concentration limits. Certain exceptions to all of these requirements are provided in paragraph (a)(4) of this section.

(1) The owner or operator of a process heater or other fuel gas combustion device subject to the SO_2 emissions limits in § 60.102a(g)(i) and (ii) 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 (40 CFR part 60, appendix B). The span values 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 (40 CFR part 60, appendix B). The owner or operator shall use Methods 6, 6A, or 6C (40 CFR part 60, appendix A) for conducting the relative accuracy evaluations. The method 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. Method 6 samples 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 (40 CFR part 60, appendix B). The span value for the O_2 monitor is 25 percent O_2.

(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. The owner or operator shall use Methods 3, 3A, or 3B for conducting the relative accuracy evaluations. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference-see § 60.17) is an acceptable alternative to EPA Method 3B.

(v) The owner or operator shall comply with the applicable quality assurance procedures in 40 CFR part 60, appendix F, including quarterly accuracy determinations for SO_2 monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(vi) Process heaters or other 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(h)(1) 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 (40 CFR part 60, appendix B). The span value for this instrument is 425 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 (40 CFR part 60, appendix B). The owner or operator shall use Method 11, 15, 15A, or 16 (40 CFR part 60, appendix A) for conducting the relative accuracy evaluations. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference-see § 60.17) is an acceptable alternative to EPA Method 15A.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in 40 CFR part 60, appendix F 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 subject to the TRS concentration limits in § 60.102a(h)(2) shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of TRS in the fuel gases before being burned in any fuel gas combustion device.

(i) The owner or operator shall install, operate, and maintain each TRS monitor according to Performance Specification 5 (40 CFR part 60, appendix B). The span value for this instrument is 425 ppmv TRS.

(ii) The owner or operator shall conduct performance evaluations for each TRS monitor according to the requirements of § 60.13(c) and Performance Specification 5 (40 CFR part 60, appendix B). The owner or operator shall use Method 16 (40 CFR part 60, appendix A) for conducting the relative accuracy evaluations.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in 40 CFR part 60, appendix F for each TRS 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 TRS in the fuel gas being burned.

(4) The owner or operator of a process heater or other fuel gas combustion device is not required to comply with paragraph (a)(1), paragraph (a)(2), or paragraph (a)(3) of this section for streams that are exempt under § 60.102(a)(i) 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)(4)(i) through (iv) of this section will be considered inherently low in sulfur content.

(i) Pilot gas for heaters and flares.

(ii) Gas streams that meet commercial-grade product specifications and have a sulfur content of 30 ppmv or less.

(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, and isomerization unit.

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

(5) If the composition of an exempt stream changes such that it is no longer exempt under § 60.102(a)(i) or it no longer meets one of the criteria in paragraph (a)(4)(i) through (iv) of this section, the owner or operator must begin continuously monitoring the stream within 15 days of the change.

(b) *Exemption from H_2S monitoring requirements for low-sulfur 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 or the TRS monitoring requirements in paragraph (a)(3) of this section for a gas stream that is inherently low in sulfur content. A gas stream that is demonstrated to be low-sulfur is exempt from the monitoring requirements of paragraph (a)(2) or (a)(3) 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 the H_2S or TRS monitoring requirements. The owner or operator shall include the following information in the application:

(i) A description of the gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the 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 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 gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested gas stream/system demonstrating that the sulfur content is less than 5 ppm H_2S or TRS. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated gas streams/systems; for infrequently operated 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 Processor Association's 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 stream for H_2S or Method 16 (40 CFR part 60, appendix A) for TRS.

(v) A description of how the 2 weeks (or seven samples for infrequently operated gas streams/systems) of monitoring results compares to the typical range of H_2S concentration (fuel quality) expected for the 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 or TRS content in the gas stream going to the loading rack flare).

(2) Once EPA receives a complete application, the Administrator will determine whether an exemption is granted. The owner or operator shall continue to comply with the monitoring requirements in paragraph (a)(2) or paragraph (a)(3) of this section until an exemption is granted.

(3) Once an exemption from H_2S or TRS monitoring is granted, no further action is required unless refinery operating conditions change in such a way that affects the exempt 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 (or TRS test, if applicable)

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 a new application 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 a new application, the owner or operator must begin continuous H_2S or TRS monitoring as required in paragraph (a)(2) or paragraph (a)(3) of this section within 15 days of the operation change.

(c) *Process heaters subject to NO_X limit.* The owner or operator of a process heater subject to the NO_X emissions limits in § 60.102a(g)(iii) 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 (40 CFR part 60, appendix B). 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. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E (40 CFR part 60, appendix A) for conducting the relative accuracy evaluations. The method 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.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of 40 CFR part 60, appendix B. The span value of this O_2 monitor is 25 percent.

(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. Method 3, 3A, or 3B shall be used for conducting the relative accuracy evaluations. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference-see § 60.17) is an acceptable alternative to EPA Method 3B.

(5) The owner or operator shall comply with the quality assurance requirements of procedure 1 in 40 CFR part 60, appendix F 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.

(d) *Excess emissions.* For the purpose of reports required by § 60.7(c), periods of excess emissions for process heaters and other fuel gas combustion devices subject to the emissions limitations in § 60.102a(g) or § 60.102a(h) are defined as specified in paragraphs (d)(1) and (3) 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 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 under paragraph (a)(1) of this section exceeds 8 ppmv.

(2) All rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under paragraph (a)(2) of this section or the average concentration of TRS as measured by the TRS continuous monitoring system under paragraph (a)(3) of this section exceeds 160 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) or the average concentration as measured by the TRS continuous monitoring system under paragraph (a)(3) 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 under paragraph (c) of this section exceeds 80 ppmv (dry basis, 0 percent excess air).

§ 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).

Option 1 for paragraph (c):

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

(1) A copy of the startup and shutdown plan required in § 60.103a(b).

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

(3) Records of bag leak detection system alarms and corrective actions according to § 63.105a(c).

(4) For each catalytic cracking unit or fluid coking unit subject to the monitoring requirements in § 60.105a(b)(3), records of the average coke burn-off rate and hours of operation.

(5) For each sulfur recovery plant subject to monitoring requirements in § 60.106a(a)(5), records of the hourly sulfur production rate and hours of operation for each sulfur recovery plant.

(6) For each fuel gas stream to which one of the exemptions listed in § 60.107a(a)(4) applies, records of the specific exemption determined to apply for each stream. If the owner or operator applies for the exemption described in § 60.107a(a)(4)(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.

Option 2 for paragraph (c):

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

(1) Records of information to document conformance with operation and maintenance requirements in § 60.105a(c).

(2) Records of bag leak detection system alarms and corrective actions according to § 63.105a(c).

(3) For each catalytic cracking unit or fluid coking unit subject to the monitoring requirements in § 60.105a(b)(3), records of the average coke burn-off rate and hours of operation.

(4) For each sulfur recovery plant subject to monitoring requirements in § 0.106a(a)(5), records of the hourly sulfur production rate and hours of operation for each sulfur recovery plant.

(5) For each fuel gas stream to which one of the exemptions listed in § 60.107a(a)(4) applies, records of the specific exemption determined to apply for each stream. If the owner or operator applies for the exemption described in § 60.107a(a)(4)(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.

Option 1 for paragraph (d):

(d) The owner or operator shall record and maintain records of discharges from any affected unit to the flare gas system. These records shall include:

(1) A description of the discharge;

(2) The date and time the discharge was first identified and the duration of the discharge;

(3) 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.

(4) The measured or estimated concentration of H_2S and SO_2 of the stream discharged. Process knowledge can be used to make these estimates;

(5) The cumulative quantity of H_2S and SO_2 released into the atmosphere. For releases controlled by flares or other fuel gas combustion units, assume 99 percent conversion of H_2S to SO_2 and no reduction of SO_2.

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

Option 2 for paragraph (d):

(d) The owner or operator shall record and maintain records of discharges from any affected unit to the flare gas system. These records shall include:

(1) A description of the discharge;

(2) The date and time the discharge was first identified and the duration of the discharge;

(3) 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.

(4) The measured or estimated concentration of H_2S and SO_2 of the stream discharged. Process knowledge can be used to make these estimates;

(5) The cumulative quantity of H_2S and SO_2 released into the atmosphere. For releases controlled by flares or other fuel gas combustion units, assume 99 percent conversion of H_2S to SO_2 and no reduction of SO_2.

Option 1 for paragraph (e):

(e) 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 (e)(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 a process unit or control system; and

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

(5) A root-cause summary report that provides the information described in paragraphs (d)(1) through (4) of this section for all discharges for which a root-cause analysis was required by § 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; and

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

Option 2 for paragraph (e):

(e) 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 (e)(1) through (6) 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 a process unit or control system;

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

(5) For any periods for which monitoring data are not available, any changes were 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;

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

(f) The owner or operator of an affected facility shall submit the reports required under this subpart to the Administrator semiannually for each 6-month period. All semiannual reports shall be postmarked by the 30th day following the end of each 6-month period.

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

(1) Approval of an alternative non-opacity emissions standard.

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

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

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

[FR Doc. E7–8547 Filed 5–11–07; 8:45 am]

BILLING CODE 6560–50–P