ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[IL–64–2–5807; FRL–6154–3]

RIN 2060–AF28

National Emission Standards for Hazardous Air Pollutants for Source Categories; National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries—Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plant Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule and notice of public hearing.

SUMMARY: This action proposes national emission standards for hazardous air pollutants (NESHAP) from process vents associated with certain new and existing affected sources at petroleum refineries. Hazardous air pollutants (HAP) that would be reduced by this proposed rule include organics (acetaldehyde, benzene, formaldehyde, hexane, phenol, dioxins, furans, toluene, and xylene) and reduced sulfur compounds (carbonyl sulfide, carbon disulfide); inorganics (hydrogen chloride, chlorine); and particulate metals (antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, and nickel). The health effects of exposure to these HAP can include cancer, respiratory irritation, and damage to the nervous system.

The standards are proposed under the authority of section 112(d) of the Clean Air Act (the Act) as amended and are based on the Administrator's determination that petroleum refinery catalytic cracking units (CCU), catalytic reforming units (CRU), and sulfur plant units (SRU) may reasonably be anticipated to emit one or more of the HAP listed in section 112(b) of the Act from the various process vents found within these petroleum refinery process units. The proposed NESHAP would protect the public health and environment by requiring all petroleum refineries that are major sources to meet emission standards reflecting application of the maximum available control technology (MACT).

DATES: *Comments.* Comments on the proposed rule must be received on or before November 10, 1998.

Public Hearing. If anyone contacts the EPA requesting to speak at a public hearing by October 2, 1998, a public hearing will be held on October 13, 1998, beginning at 10 a.m. For more information, see section VII.B of **SUPPLEMENTARY INFORMATION.**

ADDRESSES: *Comments.* Interested parties may submit written comments (in duplicate, if possible) to Docket No. A–97–36 at the following address: Air and Radiation Docket and Information Center (6102), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460. The EPA requests that a separate copy of the comments also be sent to the contact person listed below. The docket is located at the above address in Room M–1500, Waterside Mall (ground floor).

A copy of today's document, technical background information, and other materials related to this rulemaking are available for review in the docket. Copies of this information may be obtained by request from the Air Docket by calling (202) 260–7548. A reasonable fee may be charged for copying docket materials.

Public Hearing. If anyone contacts the EPA requesting a public hearing by the required date (see **DATES**), the public hearing will be held at the EPA Office of Administration Auditorium, Research Triangle Park, NC. Persons interested in presenting oral testimony should notify Ms. Jolynn Collins, Waste and Chemical Process Group, Emission Standards Division (MD–13), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, telephone number (919) 547–5671.

FOR FURTHER INFORMATION CONTACT: For information concerning the proposed regulation, contact Robert B. Lucas, Waste and Chemical Process Group, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, telephone number (919) 541–0884, facsimile number (919) 541–0246, electronic mail address, ''lucas.bob@epamail.epa.gov.''

SUPPLEMENTARY INFORMATION:

Regulated Entities. Entities potentially regulated by this action are facilities (i.e., petroleum refineries) that utilize fluid or other CCU, CRU, or SRU in their refining processes. Regulated categories and entities include:

Category	Examples of regulated entities
Industry	Petroleum Refineries (SIC 2911).
Federal government.	Not affected.
State/local/tribal government.	Not affected.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that the Agency is now aware could potentially be regulated by this action. Other types of entities not listed in the table also could be regulated. To determine whether your facility or company is regulated by this action, you should carefully examine the applicability criteria in section III.A of this document and in § 63.1560 of the proposed rule. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Internet. The text of today's document also is available on the EPA's web site on the Internet under recently signed rules at the following address: http://www.epa.gov/ttn/oarpg/rules.html. The EPA's Office of Air and Radiation (OAR) homepage on the Internet also contains a wide range of information on the air toxics program and many other air pollution programs and issues. The OAR's homepage address is: http://www.epa.gov/oar/.

Electronic Access and Filing Addresses. The official record for this rulemaking, as well as the public version, has been established for this rulemaking under Docket No. A–97–36 (including comments and data submitted electronically). A public version of this record, including printed, paper versions of electronic comments, which does not include any information claimed as confidential business information (CBI), is available for inspection from 8 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays. The official rulemaking record is located at the address in **ADDRESSES** at the beginning of this document.

Electronic comments can be sent directly to the EPA's Air and Radiation Docket and Information Center at: ''A-and-R-Docket@epamail.epa.gov.'' Electronic comments must be submitted as an ASCII file avoiding the use of special characters and any form of encryption. Comments and data will also be accepted on disks in WordPerfect in 5.1 file format or ASCII file format. All comments and data in electronic form must be identified by the docket number (A–97–36). No CBI should be submitted through electronic mail. Electronic comments on this proposed rule may be filed online at many Federal Depository Libraries.

Outline. The information in this preamble is organized as shown below.

I. Statutory Authority

The statutory authority for this proposal is provided by sections 101, 112, 114, 116, and 301 of the Clean Air Act, as amended (42 U.S.C. 7401, 7412, 7414, 7416, and 7601).

II. Introduction

A. Background

Section 112 of the Act lists HAP and directs the EPA to develop rules to control all major and some area sources emitting HAP. On July 16, 1992 (57 FR 31576), the EPA published a list of major and area source categories for which NESHAP are to be promulgated. Petroleum refineries were listed under two source categories. On December 3, 1993 (58 FR 83941), the EPA published a schedule for promulgating standards for the listed major and area sources. Standards for the first source category, ''Other Sources Not Distinctly Listed,'' were scheduled for promulgation on November 15, 1994. The EPA promulgated those standards under a July 28, 1995, court-ordered deadline; the regulations, ''National Emission Standards for Hazardous Air Pollutants: Petroleum Refineries,'' were published on August 18, 1995 (60 FR 43244). Those standards, however, did not address three process unit vents which are the subject of today's proposed rulemaking. ''Petroleum Refineries: Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plant Units'' is the second listed source category and the published schedule requires the EPA to promulgate standards for this source category by November 15, 1997.

The proposed NESHAP was developed by the EPA in concert with State regulators, industry representatives, individual States (California, Louisiana, Texas, and Illinois) and associated groups including STAPPA/ALAPCO (State and Territorial Air Pollution Program Administrators Association/Association of Local Air Pollution Control Officials). The rule development process included a cooperative effort in identifying data needs; collecting additional data; conducting emission testing with shared funding from the EPA and the California Air Resources Board (CARB); and meeting with representatives of the various stakeholders to share technical information.

Refineries affected by the standards could achieve the proposed requirements by upgrading existing emission controls, installing new control devices, or implementing source reduction measures, depending on site-specific characteristics of the source and the associated refinery operation. Alternative compliance options also are included to provide operational flexibility and to encourage pollution prevention. For example, facilities which hydrotreat to remove metals from the feed can meet the alternative nickel (Ni) standard with a less effective control device. Similarly, sulfur plants which recover additional sulfur with effective tail gas treatment can meet performance levels equivalent to facilities with a vapor incinerator.

The EPA estimates nationwide HAP emissions from the process vents on these three unit operations at about 7,270 megagrams per year (Mg/yr) (8,000 tons per year (tpy)) at current levels of control. Raising the control performance of affected petroleum refinery process units with MACT-level standards would reduce nationwide HAP emissions from process vents on the three affected unit operations by about 82 percent from the current level, with higher reductions achieved at particular sites. Other benefits of this action would include a significant decrease in nationwide emissions of non-HAP pollutants (over 132,000 tpy) and lowered occupational exposure levels for employees.

This emission reduction would be achieved with no adverse economic effects on the industry or small refineries. The nationwide total capital and annualized costs of control equipment are estimated at $173 million and $43.7 million/yr, respectively. An additional $6.5 million in total capital investment with a total annual cost of $9.8 million/yr is estimated for monitoring/implementation costs.

B. NESHAP for Source Categories

Section 112 of the Act requires that the EPA promulgate regulations for the control of HAP emissions from both new and existing major sources. The regulations must reflect the maximum degree of reduction in emissions of HAP that is achievable taking into consideration the cost of achieving the emission reduction, any non-air quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as maximum achievable control technology (MACT). For new sources, MACT standards cannot be less stringent that the emission control that is achieved in practice by the best-controlled similar source. (See CAA section 112(d)(3).) The MACT standards for existing sources cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources for categories and subcategories with 30 or more sources, or the best-performing 5 sources for categories or subcategories with fewer than 30 sources.

The control of HAP is achieved through the promulgation of either technology-based emission standards under sections 112(d) and 112(f) or work practice standards under 112(h) for categories of sources that emit HAP. Emission reductions may be accomplished through the application of measures, processes, methods, systems, or techniques including, but not limited to: (1) Reducing the volume of, or eliminating emissions of, such pollutants through process changes, substitution of materials, or other modifications; (2) enclosing systems or processes to eliminate emissions; (3) collecting, capturing, or treating such pollutants when released from a process, stack, storage or fugitive emissions point; (4) design, equipment, work practice, or operational standards (including requirements for operator training or certification) as provided in section (h); or (5) a combination of the above. (See CAA section 112(d)(2).)

C. Health Effects of Pollutants

The Clean Air Act was created in part to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population. (See CAA section 101(b)(1).) Section 112(b) of the Act lists HAP believed to cause adverse health or environmental effects. Section 112(d) of the Act requires that emission standards be promulgated for all categories and subcategories of major sources of these HAP and for many smaller ''area'' sources listed for regulation under section 112(c) in accordance with the schedules established under sections 112(c) and 112(e). Major sources are defined as those that emit or have the potential to emit at least 10 tpy of any single HAP or 25 tpy of any combination of HAP.

As previously explained, in the 1990 Amendments to the CAA, Congress specified that each standard for major sources must require the maximum reduction in emissions of HAP that the EPA determines is achievable considering cost, health and environmental impacts, and energy impacts. In essence, these MACT standards would ensure that all major sources of air toxic emissions achieve the level of control already being achieved by the better controlled and lower emitting sources in each category. This approach provides assurance to citizens that each major source of toxic air pollution will be required to effectively control its emissions. At the same time, this approach provides a level economic playing field, ensuring that facilities that employ cleaner processes and good emissions control are not at an economic disadvantage relative to competitors with poorer controls.

Emission data collected during development of the proposed NESHAP show that pollutants that are listed in section 112(b)(1) and are emitted from vents on CCU, CRU, and SRU include both inorganic HAP (including metal HAP) and organic HAP. Hazardous air pollutants from CCU include acetaldehyde, antimony, arsenic compounds, beryllium, benzene, 1,3-butadiene, cadmium, chromium, cobalt compounds, 2,3,7,8-TCDD, formaldehyde, hexane, lead compounds, mercury compounds, manganese, nickel compounds, phenol, polycyclic organic matter, toluene, and xylene. Catalytic reforming units emit benzene, chlorine, organic chlorides, naphthalene, dibenzo furans and 2,3,7,8-TCDD, polycyclic organic matter, toluene, xylene, hexane, and hydrogen chloride. Sulfur recovery plants release emissions of benzene, toluene, carbonyl sulfide, carbon disulfide, and formaldehyde. The majority of these pollutants will be reduced by implementation of the proposed emission limits. Following is a summary of the potential health and environmental effects associated with exposures, at some level, to emitted pollutants that would be reduced by the standard.

Several metals appearing on the section 112(b) list of HAP are emitted from CCU, CRU, and SRU at petroleum refineries. The nonvolatile metals of greatest concern that would be reduced by the standard are antimony, cadmium, chromium, nickel, beryllium, and manganese. These metals can cause effects such as mucous membrane irritation (e.g., bronchitis, decreased lung capacity), gastrointestinal effects, nervous system disorders (from loss of function to tremor and numbness), skin irritation, and reproductive and developmental disorders. Additionally, several of the metals accumulate in the environment and in the human body. Cadmium, for example, is a cumulative pollutant, which can cause kidney effects even after the cessation of exposure. Similarly, the onset of effects from beryllium exposure may be delayed 3 months to 15 years. Many of the metals also are known (arsenic, chromium VI, and certain nickel compounds) or probable (cadmium, lead, and beryllium) human carcinogens.

Organic compounds that would be reduced by this standard include benzene, formaldehyde, and phenol, among others. Some of the effects of these pollutants are similar to those caused by metal HAP and include irritation from short-term exposures to eye, nose, and throat; respiratory effects (expressed as labored breathing, impaired lung function); and reproductive and developmental effects. Developmental and kidney effects and cardiac effects have been reported for phenol, which is considered to be quite toxic to humans via oral exposure. In addition to these noncancer effects, formaldehyde has been classified as a probable human carcinogen. Benzene, a class A or known human carcinogen, is a concern because long-term exposure causes an increased risk of cancer in humans, and is also associated with aplastic anemia, pancytopenia, chromosomal breakages, and weakening of the bone marrow.

Emissions of carbonyl sulfide (COS) also would be reduced by the standard. Information as to the potential health effects of COS are limited. Short-term inhalation of a high concentration of COS may cause narcotic central nervous system effects and skin and eye irritation in humans. No information is available on reproductive or developmental effects from COS exposure, and the EPA has not classified this pollutant with respect to its potential carcinogenicity.

Adverse health effects from exposure to hydrogen chloride (HCl) also have been documented. Chronic occupational exposure to HCl has been reported to cause gastritis, chronic bronchitis, dermatitis, and photosensitization in workers. Acute inhalation exposure many cause coughing, hoarseness, inflammation and ulceration of the respiratory tract, chest pain, and pulmonary edema in humans. No information is available on any potential carcinogenic effects of HCl in humans and the EPA has not classified this chemical with respect to potential carcinogenicity. Only limited data are available on the reproductive and developmental effects of HCl.

In addition to HAP, the proposed standard also would reduce some of the pollutants whose emissions are controlled to meet National Ambient Air Quality Standards (NAAQS). These pollutants include particulate matter (PM), carbon monoxide (CO), volatile organic compounds (VOC), and lead. The effects of PM, CO, ozone (derived, in part, from VOC) and lead that would be reduced by this standard are described in the EPA's Criteria Documents, which support the NAAQS. Briefly, PM emissions have been associated with aggravation of existing respiratory and cardiovascular disease and increased risk of premature death. Volatile organic compounds (e.g., formaldehyde) are precursors to the formation of ozone in the ambient air.

At elevated levels, ozone has been shown in human laboratory and/or community studies to be responsible for the reduction of lung function, respiratory symptoms (e.g., cough, chest pain, throat and nose irritation), increased hospital admissions for respiratory causes, and increased lung inflammation. Animal studies have shown increased susceptibility to respiratory infection and lung structure changes. Ambient ozone also has been linked to adverse effects on agricultural crops and forests. Carbon monoxide enters the blood stream and reduces oxygen delivery to the body's organs and tissues. Exposure to CO has been associated with reduced time to onset of angina pain, impairment of visual perception, work capacity, manual dexterity, learning ability, and performance of complex tasks. Depending on the degree of exposure, lead can cause subtle effects on behavior and cognition, increased blood pressure, reproductive effects, seizures, and even death.

The EPA recognizes that the degree of adverse effects to health can range from mild to severe. The extent and degree to which the health effects may be experienced is dependent upon: (1) The ambient concentrations observed in the area, (e.g., as influenced by emission rates, meteorological conditions, and terrain); (2) the frequency of and duration of exposures; (3) characteristics of exposed individuals (e.g., genetics, age, pre-existing health conditions, and lifestyle) which vary significantly with the population; and (4) pollution specific characteristics (e.g., toxicity, half-life in the environment, bioaccumulation, and persistence).

D. Petroleum Refining Industry

The petroleum refining industry in 1997 consisted of 162 petroleum refineries operated by 90 firms in 33 States nationwide that refined approximately 15 million barrels of crude oil daily. Of the total number of U.S. refineries, 71 were located in three States (i.e., California, Texas, and Louisiana) and accounted for about 54 percent of the crude capacity. The three types of process units (CCU, CRU, and SRU) classified within the source category regulated in today's proposed rule are commonly found at petroleum refineries throughout the U.S. The processes are described below.

1. Catalytic Cracking Units

Catalytic cracking is a decomposition process whereby heavier weight, higher boiling hydrocarbons such as gas oil are broken down by heat in the presence of a catalyst to lighter weight, lower boiling, higher value hydrocarbons such as gasoline blend stocks and heating fuels. Technological developments have allowed catalytic cracking units to accept a wide range of feedstocks varying from naphtha to heavy crude residues. Current cracking catalysts incorporate zeolites (molecular sieves) with alumina-silica matrix.

Fluidized-bed or moving bed reactors are used by 101 petroleum refineries for catalytic cracking. The fluidized-bed processes are predominant but some moving bed units are still in operation. Non-fluidized CCU, which account for only 2.9 percent of the total catalytic cracking process charge rate, were operated by 7 refineries in 1997.

Fluid catalytic cracking has gained dominance in the catalytic cracking industry because these units are typically more versatile and flexible than other (non-fluid) CCU, i.e., they have improved control of process variables to maximize desired product yields. In January 1997, catalytic cracking (fluid or other) charge capacity was 5.2 million barrels per calendar day. Catalytic cracking charge capacities of less than 10,000 barrels per calendar day were reported by 9 refineries. Charge capacities of greater than 100,000 barrels per calendar day were reported by 8 refineries. About one-half of the refineries with large charge capacities have more than one CCU.

Several proprietary fluidized-bed catalytic cracking processes are available from various engineering construction companies and oil refining research and development groups. In addition, each fluidized-bed CCU operation is customized based on refinery specific process, feedstock, and product mix requirements. Catalyst and feedstock are introduced to the reactor through a vertical tube leading to the reactor, i.e., the riser; the feedstock undergoes a cracking reaction (typically in the riser) and some reaction products are deposited on the catalyst; as the mixture of catalyst and products enter the reactor vessel, steam is injected to strip products from the catalyst. With use, the catalyst in an fluidized-bed CCU unit loses activity; coke and some metals remain deposited on the catalyst. To restore catalyst activity, the used or spent catalyst is routed continuously from the reactor to a regenerator vessel; the catalyst activity is restored substantially by burning off the coke in a controlled combustion reaction; burning the coke also provides process heat necessary for the proper functioning of the fluidized-bed CCU. The source of emissions from both fluidized-bed units and moving-bed units is the regenerator flue gas stream.

There are two basic types of fluidized-bed CCU regenerators: complete burn/combustion regenerators and partial burn/combustion regenerators. In partial burn/combustion regenerators, the controlled burn involves addition of less than stoichiometric amounts of air, and thus CO is generated rather than carbon dioxide (CO_2). In complete burn/combustion (also called high temperature) regenerators, the regenerator is operated with a slight excess of oxygen (1 to 2 percent) to ensure complete combustion of the coke to CO_2; newer units are typically designed for complete combustion. The CO content of the flue gas from a high temperature, complete burn/combustion regenerator is about 0.4 percent by weight as compared to the uncontrolled CO content of about 9.3 percent from a partial burn/combustion regenerator system.

2. Catalytic Reforming Units

A CRU is designed to reform (i.e., change the chemical structure) of naphtha into higher octane aromatics. This is accomplished by passing naphtha through a reactor containing a catalyst at elevated pressure and temperature to promote dehydrogenation, isomerization, and hydrogenolysis reactions. The reforming process uses a platinum or bimetal (e.g., platinum and rhenium) catalyst material. Halides (chlorine and fluorine) promote the activity of the platinum-alumina catalyst and are stripped from the surface of the catalyst as HCl or hydrogen fluoride (HF) during the reforming reactions, thus reducing catalyst activity.

Dehydrogenation reactions are favored by low pressure and high temperature; however, coke (carbon) is also formed at low pressure which tends to deactivate the catalyst and reduce yields. Coke formation can be reduced by operating under high hydrogen pressure; other important variables in dehydrogenation activity include temperature, space velocity, recycle gas rate, and particle size of the catalyst used. The desired product quality (octane number) may be obtained by balancing the system pressure, temperature, space velocity, and recycle gas rate even as catalyst activity decreases. When yields can no longer be obtained, the catalyst must be regenerated.

In January 1997, catalytic reforming charge capacity was 3.65 million barrels per calendar day. Some form of CRU was operated by 124 refineries. The three major types of catalytic reforming processes are semi-regenerative, cyclic, and continuous. Semi-regenerative, used by 111 refineries with 49 percent of reforming capacity, is characterized by the shutdown of the entire reforming unit (which employs three to four separate reactors) at specified intervals or at the operator's convenience, for in situ catalyst regeneration. Cyclic regeneration, used by 23 refineries with 24 percent of reforming capacity, is characterized by batch regeneration of catalyst in situ in any one of several reactors (four or five separate reactors) that can be isolated from and returned to the reforming operation, while maintaining continuous reforming process operations (i.e., feedstock continues flowing through the remaining reactors). Continuous regeneration, used by 32 refineries with 27 percent of reforming capacity, is characterized by continuous flow of catalyst material through a reactor where it mixes with feedstock in counter-current direction, and a portion of the catalyst is continuously removed and sent to a special regenerator where it is regenerated and recycled back to the reactor.

3. Sulfur Plant Units

Sulfur compounds present in crude oil are converted to hydrogen sulfide (H_2S) in the cracking and hydro treating processes. The H_2S or ''acid gas'' is removed from the process vapors using amine scrubbers. Amine scrubbers also remove CO_2, COS, carbon disulfide (CS_2), nitrogen (N_2) and water (H_2O). The H_2S ''rich'' amine solution is subsequently heated to release the H_2S and other absorbed components, which is then treated in the SRU to yield high purity elemental sulfur that is sold as product. Sour water [water that contains ammonia (NH_3) and H_2S] gases are also commonly fed to the SRU. The NH_3 is oxidized to nitrogen dioxide (NO_2) and H_2O, and the H_2S is converted to elemental sulfur in the SRU.

Sulfur recovery (the conversion of H_2S to elemental sulfur) is typically accomplished using the modified-Claus process, which consists of a thermal reactor and multi-stage catalytic reactors in series. First, one-third of the H_2S is burned with air in a thermal reactor furnace to yield sulfur dioxide (SO_2). The SO_2 then reacts reversibly with H_2S in the presence of a catalyst to produce sulfur, water, and heat. Since the reaction is reversible, the reaction occurs in a series of catalytic reactors (or stages), and the vapors are cooled to condense the sulfur between each reactor to drive the reaction towards completion. The Claus gas is then reheated prior to introduction to the next catalytic reactor (or stage). The conversion efficiencies of SRU range from 92 percent for a two-stage to 97 percent for a three-stage unit.

The gas from the final condenser of the SRU (referred to as the ''tail gas'') typically consists primarily of inert gases with less than two percent sulfur compounds, which may include H_2S, SO_2, CS_2, and COS. There are numerous Claus tail gas desulfurization systems in commercial operation in the U.S. Tail gas treatment processes fall mainly into two categories: low-temperature processes and single compound processes (e.g., SCOT™, Beavon™, and Wellman-Lord™. SCOT™ tail gas treatment includes: Catalytic reduction to convert the tail gas sulfur compounds to H_2S; amine adsorption to recover and recycle any H_2S present in the tail gas; and incineration to convert the remaining tail gas sulfur compounds to SO_2. Sulfur recovery efficiencies of catalytic reduction followed by amine recovery typically range from 92 to 97 percent; therefore, the combined efficiency of the SRU and tail gas recovery systems can exceed 99.5 percent. After incineration, the treated tail gas consists primarily of inert gases with an SO_2 concentration of between 200 and 500 parts per million (ppm) with trace amounts of H_2S, COS, and CS_2.

In 1985, production of sulfur from petroleum refineries was reported at 2.9 million Mg compared to 4.2 million Mg in 1990. In 1992, 130 U.S. refineries reported operating some form of SRU with a production capacity of approximately 20,500 Mg/day. Capacities of less than 50 Mg/day were reported by 52 refineries. Capacities of greater than 300 Mg/day were reported by 24 refineries and 5 refineries reported capacities of greater than 500 Mg/day. Of the 130 refineries, 88 provided the number of SRU or Claus trains at the facility. The total number of SRU reported was 144; 38 refineries reported multiple trains with 13 refineries reporting 3 or more SRU.

A new source performance standard (NSPS) for petroleum refineries (40 CFR part 60, subpart J) limits PM and CO from fluidized-bed CCU catalyst regeneration vents, H_2S from fuel gas combustion devices, and SO_2 from SRU vents on Claus plants of greater than 20 long tons per day. This rule affects fluidized-bed CCU constructed or modified after June 11, 1973, and Claus SRU constructed or modified after October 4, 1976. Any fluidized-bed CCU, constructed or modified before January 17, 1984, 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 is exempt from the NSPS.

III. Summary of the Proposed Rule

A. Applicability

The proposed standard would apply to emissions of HAP from process vents on each affected source at any petroleum refinery that is a major source of HAP emissions as defined in § 63.2 of 40 CFR part 63. All of the nation's 162 petroleum refineries are believed to be major sources of HAP.

New and existing sources subject to the proposed NESHAP are: (1) The process vent or group of process vents on each fluidized-bed and other (i.e., non-fluid) CCU that is associated with regeneration of the catalyst used in the unit (i.e., the catalyst regeneration flue gas vent); (2) the process vent or group of process vents on each semi-regenerative, cyclic, or continuous CRU that is associated with regeneration of the catalyst used in the unit; and (3) the process vent or group of process vents that vent from each Claus or other (i.e., non-Claus) SRU or the tail gas treatment unit serving the sulfur recovery plant, that is associated with sulfur recovery. Processes which do not recover elemental sulfur do not meet the definition of a SRU, and therefore, are not subject to the proposed standards. Gaseous streams routed to a fuel gas system also are not subject to the proposed standards.

The proposed standard would prevent facilities subject to the NSPS control requirements for CCU and SRU from having to do a second compliance demonstration for the MACT standard. The owner or operator of a fluidized-bed CCU catalyst regenerator subject to and demonstrating compliance with the NSPS PM and CO standards and all associated requirements (e.g., performance test, monitoring, recordkeeping, and reporting) is considered to be in compliance with the MACT standard and associated requirements for CCU. The owner or operator of a Claus SRU subject to and demonstrating compliance with the NSPS sulfur oxides standard and associated requirements is considered to be in compliance with the MACT standard and associated requirements for SRU. Any CCU or SRU not subject to the NSPS that is subject to this MACT standard must comply with the requirements of this subpart. For example, an existing CCU not subject to the NSPS must demonstrate compliance in accordance with the requirements of this subpart. This approach is intended to reduce burden by minimizing duplication without affecting the NSPS requirements and related requirements such as new source review, prevention of significant deterioration, and other Title I requirements. The EPA requests comments on this regulatory approach or other approaches that minimize duplication without reducing or changing the NSPS standards.

B. Subcategories

Section 112(d) of the Act requires the EPA to establish emission standards for each category or subcategory of major and area sources. Section 112(d)(1) of the Act provides that the Administrator may distinguish among classes, types, and sizes of sources within a category in establishing the standards. In establishing subcategories, the EPA has considered factors such as air pollution control engineering differences, process operations (including differences between batch and continuous operations), emission characteristics, control device applicability, and opportunities for pollution prevention.

The EPA's analysis of existing CRU resulted in the designation of two subcategories for the proposed emission standard for HCl during the coke burn-off step that are based primarily on differences in the process operations, process equipment, and emissions. One subcategory is for existing units using the semi-regenerative regeneration process, and the other is a separate subcategory for units using either continuous or cyclic regeneration. The composition, quantity, and frequency of HCl emissions as well as the level of control achieved from the semi-regenerative process are quite different from those associated with the other processes. In the semi-regenerative process, emissions occur at a much lower frequency and duration because the regeneration is performed infrequently at specified intervals, which in turn affects the short-term emission rate as well as the performance and effectiveness of emission control techniques. No separate subcategories were developed for the depressurization or purge cycle because the emissions and applicable controls are similar for all three types of CRU regeneration processes. However, the proposed control requirements for CRU do not apply to depressuring and purging operations at a differential pressure between the reactor vent and the gas transfer system to the control device of less than 1 pound per square inch gauge (psig) or if the reactor vent pressure is 1 psig or less.

No subcategories were developed for the CCU catalyst regeneration vent or process vents associated with sulfur recovery plants. The MACT emission control technologies for these sources were found to be generally applicable for all of these units. However, the EPA is collecting additional information to evaluate whether additional subcategories may be warranted due to process variations and is requesting comments on this topic as discussed in section VI.D of this document. (Additional discussion of subcategorization for this source category is contained in section IV.C.1 of this document.)

C. Emission Control Technology

No additional control technology options were identified that had been demonstrated to be more effective than the MACT floor technologies that would achieve significant additional reductions in HAP emissions. Consequently, the technologies associated with the MACT floor were also determined to represent the MACT technology from this source category.

The MACT control option for emissions of metal HAP from the CCU catalyst regeneration vent during the coke burn-off is the control of PM or Ni by a wet scrubber or electrostatic precipitator (ESP), which were found to provide equivalent levels of emission control for metal HAP. The MACT control option for organic HAP from the regeneration vents for CCUs and for CRUs is complete combustion to destroy the organic compounds using complete burn/combustion regeneration process for the CCU, or venting either type of unit to a boiler, process heater, flare, or other combustion device. The MACT emission control technology for the coke burn-off during catalytic reforming regeneration is the use of a wet scrubber to remove HCl. For sulfur recovery plants, the MACT control option for organic HAP, which are reduced sulfur compounds (COS and CS_2), is oxidation to SO_2 using a vapor incinerator.

D. Emission Limits

Analysis of available information and data led the EPA to conclude that the MACT level of control for metal HAP from each new, existing, and reconstructed CCU is a PM limit for the catalyst regeneration vent of 1.0 kilogram (kg) per 1,000 kg (1.0 lb per 1,000 lb) of coke burn-off, where PM is a surrogate for total metal HAP. The proposed limit is in the same format as the NSPS (40 CFR part 60, subpart J)—kg of PM per 1,000 kg of coke burn-off. To provide flexibility in compliance and to encourage pollution prevention (such as the use of feedstocks with lower metal content), an alternative limit of 13,000 milligrams per hour (mg/hr) (0.029 lb/hr) of Ni for the catalyst regenerator vent on each CCU also is proposed.

For organic HAP from each new, existing, or reconstructed CCU, the MACT control for the catalyst regeneration vent is complete combustion, which is characterized as an emission limit of 500 parts per million by volume (ppmv) for CO as an indicator of combustion efficiency. This also is the NSPS level used to characterize complete combustion of a fluidized-bed CCU catalyst regeneration vent stream.

Proposed standards also were developed for HCl emissions from the catalyst regeneration vent on each new, existing, or reconstructed CRU. For an existing semi-regenerative unit, uncontrolled HCl emissions during coke burn-off and catalyst regeneration must be reduced by at least 92 percent or to an outlet concentration of 30 ppmv or less. For an existing unit using cyclic or continuous regeneration or a new or reconstructed unit using a semi-regenerative, cyclic, or continuous process, HCl emissions must be reduced by at least 97 percent or to an outlet concentration of 10 ppmv or less.

Organic emissions from the catalyst regeneration vent on each new, existing, or reconstructed CRU must be controlled by combustion. The owner or operator may vent emissions to a flare that meets the EPA's design and operation requirements, or use a control device to reduce uncontrolled emissions by at least 98 percent or to an outlet concentration of 20 ppmv or less.

Emissions of HAP from each new, existing, or reconstructed SRU, expressed as total reduced sulfur (TRS) compounds to represent COS and CS_2, cannot exceed a concentration of 300 ppmv.

E. Emission Monitoring and Compliance Provisions

The proposed standard requires an initial performance test to demonstrate compliance with the emission limits for vents on each CCU, CRU, and SRU. The proposed rule allows 150 days following the compliance test date to conduct the tests and report the results in the notification of compliance status report. The initial performance test for a semi-regenerative CRU may be conducted at the first regeneration cycle following the compliance date. The initial performance test, and all subsequent performance tests, are to be conducted according to the provisions in the NESHAP general provisions in 40 CFR part 63, subpart A and in the proposed rule.

For CCU, Methods 5B or 5F (40 CFR part 60, appendix A) are used to determine PM emissions, and Method 29 (40 CFR part 60, appendix A) is used to determine Ni emissions. The proposed rule includes calculation procedures to demonstrate compliance with the proposed PM limit in the kg/1,000 kg (lb/1,000 lb) of coke burn-off format and the Ni limit in the mg/hr (lb/hr) format.

The proposed rule requires a performance test by Method 10 (40 CFR part 60, appendix A) to demonstrate compliance with the CO limit for CCU catalyst regeneration vents. To determine compliance with the requirements for 98 percent removal or an outlet concentration of 20 ppmv for organic emissions from the CCU catalyst regeneration vent, either Methods 18 or 25A (40 CFR part 60, appendix A) can be used. The proposed rule contains calculation procedures and equations.

Emissions of HCl from the CRU catalyst regeneration vent are measured using Method 26A (40 CFR part 60, appendix A) to establish reduction efficiency or outlet concentration. Method 15 (40 CFR part 60, appendix A) is used to determine the concentration of TRS compounds from SRU.

Performance tests to show 98 percent destruction of organic compounds or an outlet concentration of 20 ppmv or less are not required when any of three types of control devices are used: (1) A boiler or process heater with a design heat input capacity of 44 megawatts (MW) or greater; (2) a boiler or process heater in which all vent streams are introduced into the flame zone; or (3) a flare that complies with the requirements for the proper design and operation of flares in * 63.11(b) of the NESHAP general provisions. Flares must also meet the requirements in 40 CFR 60.11(b), including the standard for visible emissions as determined using Method 22 in appendix A to 40 CFR part 60.

The owner or operator of an existing affected source has up to 3 years from the promulgation date of the final rule to demonstrate compliance. The owner or operator may request an additional year (resulting in a compliance date up to 4 years following the promulgation date of the final rule) under section 112(i)(3)(B) of the Act. A new or reconstructed source must demonstrate compliance upon startup or by the date of promulgation of this subpart, whichever is later.

The proposed standard requires the owner or operator to establish a maximum or minimum value, as appropriate, for the process and control device parameters being monitored that ensures the process or control device is operating properly so that the emission limit is not exceeded. The proposed standard allows the owner or operator to measure and record process or operating parameters on a daily average or hourly average basis, depending on the type of control device. Daily averages would be calculated as the average of all values for a monitored parameter recorded during the operating day. The average will cover a 24-hour period if the operation is continuous or the number of hours of operation per day if operation is not continuous. Monitoring data recorded during periods of unavoidable monitoring system breakdowns, repairs, calibration checks, and zero (low-level) and high-level adjustments; startup, shutdowns, and malfunctions; and periods of nonoperating of the process unit resulting in cessation of the emissions to which the monitoring applies would not be included in monitoring averages. As discussed in section VI.C of this document, the EPA requests comments on whether the monitoring averages also should exclude periods of excess emissions resulting from non-operation of a CCU control device during planned routine maintenance approved by the applicable permitting authority.

If a thermal incinerator is used, the proposed standard requires the owner or operator to monitor the daily average combustion zone temperature. Monitoring of the daily average combustion temperature also would be required for any facility using a boiler or process heater less than 44 MW design heat input capacity where the vent stream is not introduced into the flame zone. For a catalytic incinerator, the owner or operator will monitor the daily average upstream temperature and temperature difference across the catalyst bed. When a flare is used, a device capable of detecting the presence of a pilot flame is required, and the owner or operator will be required to record, for each 1-hour period, whether the monitor was continuously operating and whether the pilot flame was continuously present.

Where the owner or operator elects to use an ESP to comply with the emission limits for CCU, the average hourly voltage and secondary current to the control device or the average hourly total power input must be monitored. If the owner or operator uses a wet scrubber to comply with the requirements for either a CCU or CRU, the parameters to be monitored include the average daily pressure drop across the scrubber and the daily average flow rates of gas and water to the scrubber from which the liquid-to-gas ratio would be calculated.

For facilities complying with the CO limit of 500 ppmv for catalytic cracking regeneration, the owner or operator has a variety of monitoring options. If a combustion control device is not used to control emissions from a CCU, the average hourly temperature of the regeneration process and the oxygen content of the regeneration vent gas must be monitored. The owner or operator is not required to further monitor the process or control device if he/she demonstrates that CO emissions are less than 50 ppmv based on 30 days of continuous monitoring. Alternatively, the owner or operator could install and operate a CEM in accordance with the requirements of the NESHAP general provisions (40 CFR part 63, subpart A), Performance Specification 4A in appendix A to 40 CFR part 60, and the quality control requirements in 40 CFR part 60, appendix F.

The proposed standard would require monitoring of the daily average coke burn-off rate for each fluidized-bed CCU catalyst regeneration vent. The owner or operator would calculate and record the burn-off rate using the equation in the proposed rule.

An owner or operator using a vent system that contains a bypass line that could divert a vent stream away from the control device would be required to install a flow indicator that determines, at least once an hour, whether a vent stream flow is present or to secure the bypass line valve in a closed position with a car-seal or a lock and key configuration. If a flow indicator is used, a visual inspection must be conducted at least once every hour to demonstrate that the monitor is operating properly and that gas flow or vapor is not present. If a car-seal or lock-and-key mechanism is used, a visual inspection must be conducted at least once a month to ensure that the valve is maintained in the closed position and that no gas or vapor are present. For all bypass lines, the proposed rule also requires the owner or operator to record the times and durations of any period when the vent stream is diverted through a bypass line.

Following the performance test, more than one exceedance or excursion during a semi-annual reporting period would be a violation of the standard. As discussed in section VI.I of this document, EPA requests comment on this proposed provision. An exceedance or excursion may include: (1) An operating day when the daily average value of the monitored parameter or any period when the average hourly value of the monitored parameter, as applicable, falls below the minimum value (or exceeds the maximum value) established for the monitored parameter; (2) the average hourly CO concentration measured by a CEM exceeds 500 ppmv; (3) an operating day when all pilot flames of a flare are absent; (4) an operating day when monitoring data are available for less than 75 percent of the operating hours (or less than 18 values are recorded if an alterative data compression system is used). For a control device where more than one parameter is monitored, an excursion by more than one parameter would be considered a single violation.

The proposed NESHAP contains provisions that would allow the owner or operator to change control device and process parameter values from those established, for example, during an initial performance test, by conducting additional emission tests to verify and document compliance. A new performance test also is required to establish a revised value for the monitored parameter if there has been any change to process or operating conditions that could result in a change in control system performance since the last performance test. The owner or operator also may request to monitor other parameters. Provisions are included for the use of alternative monitoring systems such as an automated data compression system.

F. Notification, Reporting, and Recordkeeping Requirements

General notification, reporting, and recordkeeping requirements for all MACT standards are established in § 63.10(b) of the NESHAP general provisions (40 CFR part 63, subpart A). The proposed standard incorporates most of these provisions, except that minor changes were made to the notification and reporting requirements. Many initial notifications are not required or are included in the notification of compliance status report to reduce the burden and to streamline the reporting requirements. The EPA believes that these provisions will provide sufficient information to determine compliance or operating problems at the source. At the same time, the provisions are not labor intensive, do not require expensive, complex equipment, and are not burdensome in terms of recordkeeping.

1. Notifications

The proposed requirements include one-time initial written notifications of applicability for an area source that subsequently becomes a major source and for a new or reconstructed source that has an initial startup after the effective date and for which an application for approval of construction or reconstruction is not required. Notifications of intent to construct or reconstruct, the date construction or reconstruction commenced, the anticipated startup date, and the actual startup date are required for a new or reconstructed major source that has an initial startup after the effective date and for which an application for approval of construction or reconstruction is required. The owner or operator who intends to construct a new affected source or reconstruct an affected source subject to the rule, or reconstruct an affected source such that it becomes subject to the rule also must provide written notification. The application for approval of construction or reconstruction may be used to fulfill this requirement. This application must be submitted as far in advance of startup as practicable, but not later than 90 days prior to startup for a newly constructed or reconstructed source that has not started-up before the effective date. The proposed NESHAP also requires written notification of the expected date for conducting performance tests and visible emission observations for flares.

Within 150 days of the effective date, the owner or operator of an existing, new, or reconstructed affected source is required to submit a notification of compliance status report to the applicable permitting authority. In a State with an approved permit program which has not been delegated authority under section 112(l) of the Act, a duplicate report must be provided to the applicable Regional Administrator. The owner or operator may submit the information in a permit application or amendment, in a separate submittal, or in any combination. If the information has already been submitted, a separate notification is not required. The notification of compliance status report would include information on applicability; affected sources; exempted sources; control equipment or method of compliance; methods used to determine compliance (e.g., performance test results, engineering assessments, monitoring parameter values); and monitoring, maintenance, and quality assurance/quality control.

To ensure continued proper operation of the control devices, the proposed rule requires the owner or operator to include a maintenance program for control devices in the notification of compliance status report. Examples of the elements likely to be included in a maintenance plan for wet scrubbers are shown below; similar elements would be included in the plan for other types of control devices:

(1) Perform the manufacturer's recommended maintenance at the recommended intervals on fresh solvent pumps, recirculating pumps, discharge pumps, and other liquid pumps, and exhaust system and scrubber fans and motors associated with pumps and fans;

(2) Clean the scrubber internals and mist eliminators at intervals sufficient to prevent buildup of solids or other fouling that degrades performance below emission limits or standards;

(3) Conduct a periodic inspection of each scrubber and: (a) Clean or replace any plugged spray nozzles or other liquid delivery devices, (b) repair or replace missing, damaged, or misaligned baffles, trays, and other internal components, (c) repair or replace droplet eliminator elements as needed, (d) repair or replace any heat exchanger elements used for temperature control of fluids entering or leaving the scrubber, and (e) check damper settings for consistency with the air flow level used to maintain compliance and adjust as required;

(4) Initiate appropriate repair, replacement, or other corrective action when detected; and,

(5) Maintain a record (i.e., checklist), signed by a responsible plant official, showing the date of each inspection, any problems detected, a description of the repair, replacement, or other action taken, and the date of repair or replacement.

In addition to correcting defects, the owner or operator is required to ensure that the equipment is being operated at an appropriate level of reliability, i.e., without the need for continual or unusually frequent repairs or alterations that require down time. Frequent excursions of control device operating parameters would indicate that some aspect of the maintenance program or procedures is flawed.

2. Periodic Reports

The proposed NESHAP requires the owner or operator to develop and implement a written plan containing specific procedures for operating and maintaining the source during periods of startup, shutdown, and malfunctions and a program of corrective action for malfunctioning process and control systems. Each plan must contain corrective action procedures to be followed in the event any periods of excess emissions occur, including procedures to determine the cause of the problem, the time the exceedance began and ended, and for recording the actions taken to correct the cause of the exceedance or deviation. Examples of corrective action procedures that might be included in the plan for incinerators include: (1) Inspection of burner assemblies and pilot sensing devices for proper operation and cleaning; (2) adjusting primary and secondary chamber combustion air; (3) inspecting dampers, fans, blowers, and motors for proper operation; and (4)shutdown procedures.

Streamlined recordkeeping and reporting requirements also are included in the proposed rule. If actions taken during a startup, shutdown, or malfunction are consistent with the plan, no reporting would be required but a record of the event must be kept. If the actions during such an event are not consistent with the plan, the report of this occurrence must be made in the next semi-annual startup, shutdown, and malfunction report (which may be included in the semi-annual excess emissions report).

The owner or operator must submit a semi-annual report within 60 calendar days after the end of each 6-month period if any period of excess emissions occurs during the reporting period. Reports required by other regulations may be used in place or as part of the excess emissions report if the report(s) contain the required information. A report would not be required if no exceedances or excursions occurred during the reporting period. The report also would include any request for changing selection of the CCU emission standard (e.g., the PM or Ni limit) or the applicability of emission standards and requirements for CCU or SRU under the NSPS in 40 CFR part 60, subpart J or subpart UUU.

Permitting regulations in 40 CFR parts 70 and 71 require the owner or operator to make annual certifications of compliance. To aid the permitting process, the proposed NESHAP establishes conditions that must be met for the compliance certification.

3. Recordkeeping

Records required under the proposed rule are streamlined to include the minimal amount of information needed by the EPA to confirm compliance. These requirements are described in § 63.1567(e)(4) of this proposed rule. The major requirements include:

- All documentation supporting notification of compliance status;
- Startup, shutdown, and malfunction plan with supporting documentation;
- Monitoring records required by § 63.10(c) of the NESHAP general provisions;
- Each period when a monitoring system or device was inoperative or malfunctioning;
- All maintenance, corrective action, and quality assurance/quality control actions and documentation;
- Any changes to a regulated process;
- Hourly or monthly inspections of bypass line valves and bypasses;
- Hourly inspections of flare pilot flame; and
- Daily average coke burn-off rate for fluidized-bed CCU catalyst regeneration vent with supporting documentation.

All records must be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. The records for the most recent 2 years must be retained on site; records for the remaining 3 years may be retained off site but still must be readily available for review. The files may be retained on microfilm, on microfiche, on a computer, or on computer or magnetic disks.

IV. Selection of Proposed Standards

A. Selection of Source Category

Section 112(c) of the Act directs the EPA to list each category of major and areas sources as appropriate emitting one or more of the HAP listed in section 112(b) of the Act. ''Petroleum Refineries—Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plant Units'' is one of the 174 categories of sources included on the initial list of source categories (57 FR 31576, July 16, 1992).

According to the EPA's schedule for rule development for these source categories (58 FR 83841, December 3, 1993), MACT standards for these petroleum refinery process unit vents must be promulgated no later than November 15, 1997. If standards are not promulgated by May 15, 1999 (18 months following the promulgation deadline), section 112(j) of the Act requires States or local agencies with approved permit programs to issue new or revised permits containing either an emission limitation that is equivalent to the limitation that would apply if the MACT standard had been promulgated in a timely manner or an alternate emission limitation for HAP control.

Section 112(c)(3) of the Act directs the Agency to list each category of area sources that the Agency finds presents a threat of adverse effects to human health or the environment warranting regulation. Based on information and data collected during development of the proposed standard, the EPA estimates that all process units within this source category are located at major sources of HAP emission (60 FR 43245, August 18, 1995).

B. Selection of Emission Sources and Pollutants

The petroleum refinery source category, defined in the EPA report, ''Documentation for Developing the Initial Source Category List,'' (Docket Item II–A–1) specifies these three petroleum refinery process units as a source category for regulation. Because little or no HAP emission data for this source category were available at the beginning of this study, the EPA collected information and data through review of existing literature. Section 114 questionnaires were sent to nine corporations (representing 27 refineries) and information collection requests (ICRs) were sent to the remainder of existing U.S. refineries to obtain information and data on refineries during development of the initial MACT rule for petroleum refineries (60 FR 43244, August 18, 1995). Site surveys were conducted by the EPA at 20 petroleum refineries as part of the refinery process vent rule development. Also, as part of the information and data collection process, a series of meetings were held with State representatives and industry trade associations (i.e., the American Petroleum Institute (API) and the National Petroleum Refiners Association (NPRA)) to first inform the industry of the EPA's intentions to develop a MACT for this source category and also to solicit their input. As a result, the trade associations conducted surveys of their member companies to collect additional information and data relative to the three process unit operations which would be regulated by today's proposed rule. Based on this information and data, and for the reasons described below, the EPA is regulating these three vents as emission sources under the proposed rule.

C. Selection of Proposed Standards for Existing and New Sources

1. Background

After the EPA has identified the specific source category or subcategories of major sources for regulation under section 112, MACT standards must be established for each category or subcategory. Section 112 of the Act sets a minimum level or floor for the standards. For new sources, standards for a source category or subcategory cannot be less stringent than the emission control that is achieved in practice by the best-controlled similar source. (See CAA section 112(d)(3).) The standards for existing sources can be less stringent than the standards for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources for categories or subcategories with 30 or more total sources, or the best performing 5 sources for categories or subcategories with fewer than 30 sources. These minimum requirements for the MACT emission limitation(s) for new and existing sources are termed the ''MACT floor.''

After the floor has been determined for a new or existing source in a source category or subcategory, the Administrator must set MACT standards that are technically achievable and no less stringent than the floor. Such standards must be met by all sources within the category or subcategory. In establishing the standards, the EPA may distinguish among classes, types, and sizes of sources within a category or subcategory. (See CAA section 112(d)(1).)

The next step in establishing MACT standards is traditionally the investigation of regulatory alternatives. With MACT standards, only alternatives at least as stringent as the floor may be selected. Information about the industry is analyzed to develop model plants for projecting national impacts, including HAP emission reduction levels and cost, energy, and secondary impacts. Regulatory alternatives, which may be different levels of emissions control equal to or more stringent than the floor levels, are then evaluated to select the regulatory alternative that best reflects the appropriate MACT level. The selected alternative may be more stringent than the MACT floor, but the control level selected must be technically achievable. The regulatory alternatives and emission limits selected for new and existing sources may be different because of different MACT floors.

When the EPA considers an alternative which is beyond-the-floor, the EPA examines the achievable emission reductions of HAP (and possibly other pollutants that are co-controlled), cost and economic impacts, energy impacts, and other non-air environmental impacts. The objective is to achieve the maximum degree of emissions reduction without unreasonable economic or other impacts. (See CAA section 112(d)(2).)

Under the Act, subcategorization within a source category may be considered when there is enough evidence to demonstrate clearly that there are significant differences among the subcategories. The criteria to consider include process operations (including differences between batch and continuous operations), emission characteristics, control device applicability, safety, and opportunities for pollution prevention.

The EPA examined the three process unit operations, the operating characteristics of these units, and other relevant factors to determine if separate classes of units, operations, or other criteria have an affect on air emissions from any of the three process unit operations in this source category. For SRU, no basis was established to subcategorize or develop separate standards within these unit operations. For CCU, the EPA requests additional information and data needed to address the potential need for subcategorization due to process variations (e.g., the differences between fluidized-bed and non-fluidized bed CCU). However, for CRU, an analysis of the information and data in the EPA refinery database indicated significant differences in both the operating processes and emission controls associated with semi-regenerative CRU during the catalyst regeneration coke burn-off step. Therefore, the EPA established a subcategory for semi-regenerative CRU based on the operating differences and control device performance during the coke burn-off step; a separate performance standard was established for this subcategory. Cyclic and continuous CRU were grouped together and have a different performance standard for the coke burn-off step. Subcategorization of semi-regenerative CRU is further discussed in sections III.B and IV.C.2.b of this document.

2. MACT Floor Technology and Emission Limits

In establishing the MACT floor for existing sources, sections 112(d)(3) (A) and (B) of the Act directs the EPA to set standards that are no less stringent than the ''average'' emission limitation achieved by the best performing 12 percent (for which there are emissions data) where there are more than 30 sources in the category or subcategory or the best performing five sources (for which there are emissions data) where there are fewer than 30 sources. Among the possible meanings for the word ''average'' as the term is used in the Act, the EPA considered two of the most common.

First, ''average'' could be interpreted as the arithmetic mean. The arithmetic mean of a set of measurements is the sum of the measurements divided by the number of measurements in the set. The EPA has determined that the arithmetic mean of the emission limitations achieved by the best performing 12 percent of existing sources (or best five sources where there are fewer than 30 sources) in some cases would yield an emission limitation that fails to correspond to the emission limitation achieved by any particular technology. In such cases, the EPA would not select this approach. The word ''average'' could also be interpreted as the median emission limitation value. The median is the value in a set of measurements below and above which there are an equal number of values (when the measurements are arranged in order of magnitude). This approach identifies the emission limitation achieved by those sources within the top 12 percent (or top five where there are fewer than 30 sources), arranges those emissions limitations in order of magnitude, and the control level achieved by the median source is selected. Either of these two approaches could be used in developing standards for different source categories.

A ''technology'' approach also was used in developing these proposed standards. For each source type, the control technologies were ranked in the database by performance and the median technology represented by the best-controlled sources was selected as the MACT floor. Sources having control technology representative of the MACT floor were then evaluated and analyzed in order to determine an appropriate emission limitation to characterize performance of the MACT floor technology.

As previously noted, data related to operating procedures and emissions for the three process unit operations were obtained through a combination of literature sources, site visits, ICR, discussions with industry and State Agency representatives, and information surveys conducted by industry trade associations. These data were then compiled into a comprehensive database that was used for the floor analysis.

a. MACT floor for catalytic cracking units. Catalytic cracking (fluid and other) units emit a variety of HAP during catalyst regeneration; these HAP can be broadly categorized into two groups: metallic HAP (e.g., antimony, beryllium, mercury, and nickel) and organic HAP (e.g., benzene, formaldehyde, hexane, and xylene). While not exclusively so, the metallic HAP emitted from CCU catalyst regeneration vents are primarily emitted as PM. Mercury is the one metallic HAP that is expected to be emitted in both solid and gaseous forms. The organic HAP emitted from CCU catalyst regeneration vents are in the vapor phase. These two HAP emission forms require significantly different control technologies.

The EPA database for CCU contains a considerable amount of information on control device types as well as process information, but very limited information on vent stream composition or HAP concentration for either the metallic HAP or the organic HAP. The amount of constituent data currently available is not adequate to establish a MACT floor for each individual HAP; the limited data on individual HAP cannot be considered representative of the entire industry in all but a few cases. Therefore, the floor for CCU (both fluidized bed and non-fluidized bed) catalyst regeneration vent HAP emissions is being established for the broad classes of HAP that are grouped as either metallic HAP or organic HAP.

The EPA is aware that there are significant process differences between the fluidized-bed and non-fluidized bed CCU. These process differences include such things as catalyst size and composition, as well as reactor operation (e.g., plug downflow versus fluidized riser processes). At this time, the EPA does not have adequate data to characterize the HAP emissions from the non-fluidized CCU, but preliminary data currently available indicate, based on the EPA's current understanding, that these units are likely operating at emission levels that meet the MACT floor criteria. However, the EPA is gathering additional information and data on these processes and, based on the new information, will reexamine the possible need to set a separate standard for these few non-fluidized CCU.

(1) Organic HAP MACT floor.

(a) Existing catalytic cracking units. Available emission data have been reviewed to identify the best performing 12 percent of existing sources. The available emissions data that relate to organic HAP control performance are presented in the database in terms of VOC, THC, and CO with only minimal data on individual HAP constituents. The performance level formats available in the database that relate to organic HAP are an emission rate normalized to coke burn, an emission rate expressed in terms of an exit concentration, and a performance level expressed as a percent reduction achieved. The amount of individual constituent data currently available is not adequate to establish a MACT floor for each individual organic HAP; the limited data on individual organic HAP cannot be considered representative of the entire industry. Therefore, emissions data on VOC, THC, and CO were reviewed since these data are indicative of emissions of individual organic HAP.

The CCU catalyst regeneration step that generates the affected gas stream involves an initial combustion operation, and the catalyst regeneration step can be conducted either as a partial combustion operation or a complete combustion operation. A complete burn/combustion CCU has a catalyst regeneration coke burn stage designed and operated with a residence time, temperature, and excess oxygen level to achieve complete oxidation of the coke or carbon to CO_2; a partial burn/combustion CCU has a catalyst regeneration coke burn stage designed and operated with less than stoichiometric oxygen, which results in incomplete combustion of the carbon and is characterized by high levels of CO.

The emission data for CCU catalyst regeneration vents indicate that: (1) Complete burn/combustion CCU and (2) partial burn/combustion CCU that are followed by a CO boiler or other combustion device achieve similar organic emission rates. Both of these configurations achieve complete combustion of the CCU catalyst regeneration vent gases and demonstrate similar emissions rates and as a result, both are considered types of ''complete combustion.'' These complete combustion units have significantly less organic HAP emissions than partial burn/combustion CCU that are not followed by an additional combustion device.

The petroleum refinery NSPS (40 CFR part 60, subpart J) is a regulation that requires catalyst regeneration vent gases from new or reconstructed fluidized-bed CCU to have complete combustion by limiting the CO concentration to less than or equal to 500 ppmv (dry). Information gathered by the EPA indicates that more than 12 percent of the existing CCU are currently subject to the petroleum refinery NSPS. The NSPS thus represents the average emission limitation achieved, in terms of a regulatory requirement, by the best performing 12 percent of existing sources. Therefore, a complete burn/combustion CCU or partial burn/combustion CCU followed by a CO boiler or other combustion device that reduces the CO concentration in the catalyst regeneration vent gas to 500 ppmv or less is deemed to be meeting the MACT floor for existing CCU.

(b) New catalytic cracking units. Based on the information and data available, the EPA concluded that the MACT floor determination for existing CCU sources of organic HAP (i.e., complete combustion of the vent gases) also represents the HAP emission control that is achieved in practice by the best-controlled similar source in the source category. Therefore, the MACT floor for new sources is the same as that for existing sources for organic HAP. This fact also leads to the conclusion that there is no technology that has been demonstrated in this industry to provide a level of control more stringent than the MACT floor for organic HAP.

(2) Metallic (or inorganic) HAP MACT floor.

(a) Existing catalytic cracking units. Along with low emissions, the best-performing existing sources are expected to have the best-performing control technologies; for metallic HAP that would involve either a modern ESP or a venturi scrubber. Available data shows these two devices, used by approximately 45 percent of the industry, provide similar control of PM and metallic HAP. However, some refineries with CCU controlled only by tertiary cyclones, control devices typically considered less effective, have told the EPA that their emissions are equivalent to those achieved by the more efficient control devices. This is in large part a function of the site-specific characteristics of the unit (e.g., a low Ni feed) Therefore, rather than set an equipment standard based on a control device, the EPA prefers to establish a performance standard associated with the best performing control technology.

The petroleum refinery NSPS (40 CFR part 60, subpart J) is a performance standard that requires new or reconstructed fluidized-bed CCU to reduce PM emissions from the catalyst regeneration vent to 1 kg/1,000 kg (1 lb/1,000 lb) of coke burn-off. As previously noted, the information gathered by the EPA and contained in the petroleum refinery database indicates that more that 12 percent of the existing CCU are currently subject to the petroleum refinery NSPS. The EPA reviewed this emission standard to determine its appropriateness as a performance standard to characterize the best-performing control technology for CCU metallic HAP emissions. The EPA concluded that for a variety of reasons, PM is considered a reasonable surrogate for total metallic HAP (excluding mercury):

(1) The metallic HAP emitted from CCU catalyst regenerator vents are primarily emitted as PM;

(2) In the EPA report, ''Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report'' (Docket Item II–A–6), it was determined that for those combustion operation vent gases ''the HAP metals that exist primarily in particulate form are readily controlled by PM control devices''; and

(3) There is a considerable amount of emission data available for PM emitted from CCU catalyst regeneration vents.

The performance level formats available in the data base for PM are an emission rate normalized to coke burn, an emission rate expressed in terms of an exit concentration, and a performance level expressed as a percent reduction achieved. The EPA refinery database shows that CCU ESP achieve a PM emission rate that ranges from 0.0002 to 3.6 lb/1,000 lb coke; the 26 values reported have a median of 0.81 and a mean of 0.86 lb/1,000 lb. The NSPS value is 1.0. Nineteen of the 26 CCU have a catalyst regeneration PM emission rate of less than 1 lb/1,000 lb of coke burn-off. The five CCU that use a venturi scrubber and that have PM data show a range of emissions from 0.36 to 0.86 lb/1,000 lb of coke burn-off, which is within the range of performance shown by the ESP. Thus, the NSPS PM emission limit for the catalyst regeneration vent of 1 lb/1,000 lb of coke burn-off appears to a reasonable characterization of PM control device performance on a ''not-to-be-exceeded'' basis, based on the available data. As a result of this analysis, a PM emission limit of 1 lb/1,000 lb of coke burn-off is selected to characterize the MACT floor for catalyst regeneration vents on existing units.

In addition to characterizing the MACT floor performance in terms of a PM emission limit, it is possible to determine an alternative MACT floor technology emission limit in terms of the entire metal HAP population or an individual metal HAP (i.e., Ni) within that population. The reason for determining a MACT floor emission limit as an alternative to the PM level but formatted in a terms of total metal HAP or an individual metal HAP is to provide for increased operational flexibility and to allow opportunities for pollution prevention when complying with a MACT standard for this source category.

In developing a MACT floor emission level formatted in terms of the population of metal HAP emitted by CCU, the approach used involved analysis of the available metal HAP data. This is most readily done using Ni as a surrogate for total metal HAP. Nickel emissions data were used for this comparative analysis because of the relative abundance of measured Ni emissions data and the paucity of emissions data available for other metal HAP. Nickel emissions data (formatted in terms of mass per unit time) for catalyst regeneration vents are available for 23 CCUs. The available measured Ni emissions data from CCU catalyst regeneration vents in the EPA refinery database were examined and compared to determine the representativeness of these data.

In examining the database, EPA determined that the Ni emission data currently available for CCU catalyst regeneration vents is representative of the best-performing units in the industry. The EPA based this conclusion on the following considerations. A primary factor that influences the Ni emissions from the CCU catalyst regeneration vent is the Ni content in the CCU feed. The Ni emission rates in the refinery database are for the most part from units with low Ni feed. There are 72 CCU that reported the Ni content in their CCU feed. Of these 72 CCU, 43 (or 60 percent) of the units had Ni feed concentrations of 1 ppmw or lower. However, 12 of 14 CCU (or 86 percent of the CCU) that reported both Ni emissions data and Ni feed content, had Ni feed concentrations of 1 ppmw or lower. In addition, the database reflects Ni emission rates of refineries that hydrotreat the CCU feed. Hydrotreating the CCU feed tends to lower the CCU feed Ni content. There are 98 CCU that reported the use or non-use of hydrotreating. Of these 98 CCU, 56 (or 57 percent) of the units hydrotreat. However, 13 of 17 CCU (or 76 percent of the CCU) that reported both Ni emissions data and hydrotreating information, hydrotreat their CCU feed.

A second factor that influences the Ni emissions from the CCU catalyst regeneration vent is the level of PM control on the unit. The EPA refinery database is comprised of units that are subject to stringent regulatory requirements that result in control of Ni emissions. For example, from the data collected by API and provided to the EPA as a part of the database, it appears that at least 36 percent of the CCU that reported Ni emissions data are subject to the NSPS, whereas the EPA estimates that there are approximately 17 percent of the CCU in the entire industry subject to the NSPS. In addition, approximately 41 percent of the Ni emissions data are from CCU at California refineries, where the State regulations on PM control are basically the same as the NSPS PM emission control requirements, whereas California refineries operate only about 10 percent of the total number of CCU in the U.S. Also, approximately 81 percent of the CCU in the database that reported Ni emissions data operate either an ESP or venturi wet scrubber on the CCU catalyst regeneration vent, whereas only 63 percent of the CCU nationwide operate either an ESP or venturi wet scrubber on the CCU catalyst regeneration vent.

For the reasons discussed above, the EPA considers the available Ni emissions data to be representative of the best-performing CCU sources, rather than the industry as a whole. Examination of the emission data shows an emission rate for the top 12 percent to be 0.055 tpy. In conjunction with this, the available Ni source test data were analyzed to determine the variability of individual source test runs for a given CCU source test. Based on analysis of the relative standard deviation of the individual CCU source test data, the standard deviation for a unit with emissions of 0.055 tpy is 0.042. Using the upper 95th percentile of a normal distribution (i.e., a z-statistic equal to 1.645), the Ni emission limit determined to reflect the best performing 12 percent of existing sources is a Ni emission limit on a not-to-be-exceeded basis of 0.125 tpy (250 lb/yr) or 0.029 lb/hr (i.e., the mean + 1.645 standard deviations). Therefore, a metal HAP MACT floor emission limit of 13,000 mg/hr or 0.029 lb/hr of Ni also has been determined to characterize the performance of the MACT floor control technology for existing CCU catalyst regeneration vents.

(b) New catalytic cracking units. Based on the information and data available, the EPA concluded that the MACT floor determination for existing CCU sources of metallic HAP (i.e., use of a PM control device such as an ESP or venturi scrubber) also represents the HAP emission control that is achieved in practice by the best-controlled similar source in the source category. Therefore, the MACT floor for new sources is the same as that for existing sources for metallic HAP. This fact also leads to the conclusion that there is no technology that has been demonstrated in this industry to provide a level of control more stringent than the MACT floor for metallic HAP.

(3) Mercury MACT floor. Mercury (Hg) is not well controlled by PM air pollution control devices (ESPs as well as PM scrubbers). This situation would be expected because Hg is likely emitted in both a solid and gaseous or vapor-phase (elemental) form; the fact that ''conventional (PM) controls are generally inconsistent in their effectiveness'' with regard to Hg removal is documented in the EPA report, ''Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report''. (See Docket Item II–A–6.) Combustion devices for control of organic vapor would also provide no control for Hg. There are a number of emerging technologies (such as activated carbon injection) but none have been show to be applicable to CCU catalyst regeneration vents. Therefore, the MACT floor for Hg is determined to be no control for both new and existing units.

b. MACT floor for catalytic reforming units. Developing a MACT floor for CRU catalyst regeneration vents is complicated by the fact that there are three types of CRU (continuous, cyclic; and semi-regenerative), and there are different steps (times and locations) during which vent emissions may occur during CRU catalyst regeneration: (1) Initial depressurization/purge; (2) coke burn-off; (3) catalyst rejuvenation; and (4) final purge. The depressurization/purge vent gas contains primarily hydrocarbons from the CRU feedstock that remain on the reforming catalyst feed (e.g., benzene, toluene, hexane, and ethylbenzene). The predominant HAP emitted during coke burn-off are HCl and Cl_2. Chlorinated organic compounds used for catalyst rejuvenation (e.g., trichloromethane and perchloromethane) as well as residual HCl on the reforming catalyst may be emitted during catalyst rejuvenation and final purge.

The EPA database for CRU contains a considerable amount of information on control device types as well as process information for 177 CRU, but very limited information on vent stream composition or HAP concentration. There are some data available to characterize HCl emissions during coke burn-off; however, the limited data on HCl emissions cannot be considered representative of the entire industry as most HCl emissions data are from continuous or cyclic units. The available data on HAP emissions from CRU catalyst regeneration vents is inadequate to characterize the emission reductions achieved by the top-performing 12 percent of the units during the depressurization/purge, catalyst rejuvenation, and final purge cycles. Therefore, the MACT floor for CRU catalyst regeneration vent HAP emissions is established for each potential CRU vent based on current industry practices rather than HAP specific emissions data.

(1) *MACT floor determination for existing CRU catalyst regeneration vents.*

(a) MACT floor for CRU depressurization/purge vent. Given the limitations of the available data, the MACT floor determination for the CRU depressurization/purge vent is based on current practices in use and control equipment in place at CRU. Flares, process heaters or other combustion devices are used for 21 of the CRU catalyst regeneration vents. Based on current information in the EPA database, it is difficult to discern whether these control devices are used specifically for the depressurization/purge vent. However, all of the 20 refineries visited by either the EPA or CARB during information collection site visits to support the development of this rule vented the depressurization/purge gases to either the refinery fuel gas system or to a flare. Therefore, based on operational practices for over 12 percent of the CRU (and 100 percent of the units for which the EPA has firsthand information), the MACT floor for emissions vented during the depressurization/purge cycle is venting to a combustion device.

In the first petroleum refinery MACT rule (60 FR 43244, August 18, 1995), the EPA assigned a performance value for combustion units serving miscellaneous process vents. In that floor analysis, it was assumed that the various combustors were all well designed and operated and would achieve 98 percent destruction of total VOC (and HAP). (See Docket A–93–48, Docket Item IV–B–12.) This same performance level is therefore assumed for combustion devices that are used on CRU catalyst regeneration vents. Therefore, the MACT floor for emissions vented during the depressurization/ purge cycle is venting to a combustion device that achieves a 98 percent destruction efficiency or reduces the total organic HAP or the TOC concentration to below 20 ppmv.

The 20 ppmv concentration format is included as an alternative in the proposed standard because the rule could apply to dilute process vent streams and the proposed standard for combustion devices is formatted in terms of a weight-percent reduction. The EPA believes the proposed standard for combustion devices needs to include the volume concentration alternative to account for the technological limitations of enclosed combustion devices treating dilute streams. (See 48 FR 48933, October 21, 1983.) Below a critical concentration level, the maximum achievable efficiency for enclosed combustion devices decreases as inlet concentration decreases. Consequently, for streams with low organic vapor concentrations, the 98-percent mass reduction may not be technologically achievable in all cases. Available data show that 20 ppmv is the lowest outlet concentration of total organic compounds achievable with control device inlet streams below approximately 2,000 ppmv total organics. Therefore, the concentration limit of 20 ppmv has been added as an alternative standard for incinerators, process heaters, and boilers to allow for the drop in achievable destruction efficiency with decreasing inlet organics concentration.

(b) MACT floor for CRU catalyst regeneration coke burn-off vent. The EPA examined the available HCl emissions data for catalyst regeneration vents on 22 CRU that reported HCl emissions during the coke burn-off cycle, along with the type of CRU and the control device used; 17 of these units operate with no emission controls (or unknown emission controls). With the limited data available, it is not possible to characterize these emissions data as either representative of the industry as a whole or representative of the top-performing CRU. For example, only 3 (or 14 percent) of the 22 units that reported HCl emissions are semi-regenerative CRU, while semi-regenerative CRU represent 61 percent of all CRU. It appears that due to the limited frequency and duration of the emissions from catalyst regeneration vents on semi-regenerative units, few emission source tests have been performed at semi-regenerative CRU. Therefore, a MACT floor determination cannot be based on the available HCl emissions data for the coke burn-off cycle. However, a determination based on control technology can be made.

From a review of the process equipment data, two classes of scrubbers were designated to characterize the general classes or groups of scrubbers being used to control emissions from CRU catalyst regeneration vents during the coke burn-off step: single theoretical stage scrubbers and multiple theoretical stage scrubbers. The single theoretical stage scrubber classification was used to reflect the following CRU scrubbing systems, most of which are considered internal to the process: Caustic injection, spray circulating solution, hydrocyclone, and once through spray scrubbers. Multiple theoretical stage scrubbers which are, for the most part, external to the process include: Packed tower, packed column, plate and spray, venturi, and otherwise unspecified absorbers or scrubbers. Although there are inadequate CRU emissions data to differentiate the removal efficiency between single stage scrubbers and multiple stage scrubbers, theoretical considerations suggest that multiple stage scrubbers will have a higher HCl removal efficiency than a single stage scrubber.

A summary of the numbers of each type of control device (single or multiple stage) for catalyst regeneration vents on each type of CRU (continuous, cyclic, or semi-regenerative) shows that for continuous CRU, 28 percent use multiple stage scrubbers while only 6 percent use single stage; for cyclic CRU, 36 percent use multiple stage while only

11 percent use single scrubbers; and for semi-regenerative CRU, only 3 percent use multiple while 72 percent use a single stage scrubber. Based on these data, the MACT floor for catalyst regeneration vents on continuous and cyclic CRU is the use of a multiple stage scrubber during the coke burn-off process. The MACT floor for catalyst regeneration vents on semi-regenerative CRU is the use of a single stage scrubber during the coke burn-off process. Subcategorizing semi-regenerative CRU is justified based on the operational differences of semi-regenerative units (i.e., primarily annual hours the system is regenerating). Based on the similarities of the types of controls used for catalyst regeneration vents on cyclic and continuous CRU and the annual operating hours in which regeneration occurs, it appear reasonable that cyclic and continuous CRU be grouped together.

The performance of CRU scrubbers can be characterized based on industry surveys and source test data on HCl scrubbers used in another industry—the steel pickling industry. Data from that industry contains a range of flow rates and HCl concentrations which span the flow rates and HCl concentrations expected for the CRU catalyst regeneration coke burn-off vent. The characteristics of the single and multiple stage scrubbers that constitute existing source and new source levels of control were determined in terms of both HCl reduction efficiency and maximum outlet concentration by evaluating the results of emissions tests conducted on units currently employed in the steel pickling industry. The data from these tests are presented and discussed in detail in the preamble to the proposed rule (62 FR 49052, September 18, 1997) and in the background information document for the proposed standard. (See Docket Items II–A–4.) While wet scrubber control devices are normally designed for a target emission reduction efficiency, the EPA is aware that high reduction efficiencies for process gases that contain low concentrations of HCl or HCl in aerosol or droplet form may not always be achievable. The EPA therefore has characterized scrubber performance in terms of a maximum exhaust gas concentration as well as reduction efficiency in recognition of the limitations of the technology.

Based on the median performance of the multiple stage type scrubbers tested, the EPA selected an HCl scrubber removal efficiency of 97 percent or an outlet concentration of 10 ppmv or less to characterize the performance of a multiple stage HCl scrubber. That is, the EPA considers that a well-operated and well-maintained scrubber, i.e., those considered to be the MACT floor for catalyst regeneration vents on continuous and cyclic CRU, can achieve a 97 percent removal efficiency or reduce the outlet concentration to 10 ppmv or less. Therefore, the MACT floor for the coke burn-off vent for continuous and cyclic CRU is to operate a scrubber that achieves 97 percent or greater removal of HCl or achieves an outlet concentration of 10 ppmv or less.

As previously noted, there are few data to support the selection of emission limits or HCl control efficiency values for the MACT floor for catalyst regeneration vents on semi-regenerative CRU (i.e., single stage scrubbers). Examination of performance data of scrubbers used outside the source category shows that the lowest control efficiency of HCl scrubbers tested by the EPA in the steel pickling industry was approximately about 92 percent. (See Docket Item II-A–4.) Based on these available data and theoretical engineering design considerations of the various HCl single stage scrubber types, a single stage HCl scrubber can reasonably be expected to achieve a 92 percent HCl removal efficiency on an industry-wide basis for semi-regenerative CRU catalyst regeneration coke burn-off vents. This is equivalent to an outlet concentration limit of 30 ppmv, based on the 92 percent HCl removal efficiency. Therefore, the MACT floor for the catalyst regeneration coke burn-off vent for semi-regenerative CRU is to operate a scrubber that achieves 92 percent or greater removal of HCl or achieves an outlet concentration of 30 ppmv or less.

(c) MACT floor for CRU catalyst regeneration rejuvenation vent. As noted previously, there are very few data available to characterize emissions from the CRU catalyst regeneration rejuvenation/final purge vent. Additionally, from information gathered during site visits to petroleum refineries, there appear to be differences in how/when the rejuvenation process occurs. Some units dose the chlorination agent into the CRU reactors during the coke burn-off cycle (''coincidental rejuvenation''). In this instance, the rejuvenation and coke burn-off vent coincide, and the MACT floor for coke burn-off vents previously described would apply. Other units circulate the chloriding agent through the reactor(s) upon completion of the coke burn-off cycle (''sequential rejuvenation''). In this instance, the system is a closed recirculation loop with no atmospheric venting. If venting does occur during sequential rejuvenation, then the MACT floor is venting to an HCl scrubber with the same efficiencies specified for the coke burn-off vent. The EPA requests specific comments regarding the prevalence, operations, and controls typically associated with this vent.

(d) *MACT floor for CRU catalyst regeneration final purge vent.* Upon completion of the rejuvenation/coke burn-off cycles, the CRU system is purged to remove oxygen from the system and to create a reducing atmosphere prior to bringing the unit or reactor back on-line for reforming (or returning the catalyst to the reforming reactor in the case of continuous units). This final purge vent may be scrubbed, released to the atmosphere, vented to the refineries fuel gas system, or vented to a flare or other combustion control device. Flares, process heaters or other combustion devices are used for catalyst regeneration vents on 21 of the CRU. Based on current information in the EPA database, it is not possible to discern whether these control devices are used specifically for the final purge vent. However, from information collected during the site visits to 20 refineries, it is known that approximately one-half of these refineries vented the final purge vent to a combustion control device. Using the control efficiency determined by the EPA for combustion devices (refer to the discussion for the depressurization/purge vent), the MACT floor for the final purge vent is to vent this stream to a combustion control device that achieves 98 percent destruction efficiency or reduces total organic HAP or TOC concentration to below 20 ppmv.

(2) MACT floor determination for new CRU catalyst regeneration vents. Except for the catalyst regeneration coke burn-off vent for semi-regenerative CRU, the MACT floor for catalyst regeneration vents on new CRU is the same as for catalyst regeneration vents on existing CRU for all CRU catalyst regeneration vents. This is because the catalyst regeneration vent on the best-controlled or top-performing CRU applies the same work practices or control devices as the top 12 percent of CRU catalyst regeneration vents employ (i.e., the MACT floor for existing sources). There are two semi-regenerative CRU that employ multiple stage type scrubbers to control catalyst regeneration coke burn vents. These represent the best-controlled sources for this vent. Therefore, the MACT floor for catalyst regeneration vents on new semi-regenerative CRU (as well as continuous and cyclic CRU) is the use of a multiple stage scrubber (i.e., a scrubber that achieves 97 percent or greater removal

of HCl or achieves an outlet concentration of 10 ppmv or less as specified in the MACT floor for catalyst regeneration vents on existing continuous and cyclic CRU).

c. MACT floor for sulfur recovery plants. Developing a MACT floor for SRU is complicated by the fact that there are different types of processes (although Claus units predominate the industry) and numerous types of emission control techniques (including different types of tail gas treatment units, thermal incineration, or a combination of a tail gas treatment unit and incineration). The EPA database for SRU contains information regarding the number and types of SRUs as well as the control device configuration for 144 units at 82 refineries. The database also has information regarding process capacities or sulfur production rates and information regarding applicability of the NSPS for approximately 60 percent of these SRU.

The predominant HAP emitted from SRU are COS and CS_2. There are very few data available regarding HAP emissions from SRUs. Consequently, the available data on HAP emissions from the SRU vents are inadequate to characterize the emission reductions achieved by the top performing 12 percent of the units. Additionally, there are inadequate data to determine and differentiate the emission reduction efficiencies achieved by the various types of emission control process configurations. Therefore, the floor for SRU vent HAP emissions is being established based on current industry regulations rather than emissions data or process equipment.

(1) MACT floor determination for existing SRU/sulfur plant vents. There are 144 units in the current data base for SRU; information regarding the applicability of the refinery NSPS was specifically requested for 91 of these units. Of the 91 SRU for which NSPS applicability information was requested, 38 units were subject to the NSPS, 47 units were not, and 6 units did not respond. Due to the lack of emissions data, a MACT floor determination cannot be made based on the emission reduction achieved by the top-performing 12 percent of the industry. Alternatively, the MACT floor determination can be made based on either the emission control equipment in-place for the SRU vent or the existing regulations limiting HAP emissions from these vents.

Although the database contains information regarding the types of equipment in-place at the SRU, due to the variety of different tail gas treatment units and process configurations and the lack of emissions data, it is not possible to make a ranking of the tail gas treatment unit types and the process configurations that yield the greatest reduction in HAP emissions. On the other hand, the petroleum refinery NSPS (§ 60.104) specifies emission limits (some of which are primarily HAP emission limits) for Claus sulfur recovery plants. As Claus units represent 96 percent of the SRU in the EPA database (138 of the 144 SRU are Claus units), and approximately 40 percent of the SRU (for which NSPS applicability information is available) are subject to the NSPS, it is concluded that over 12 percent of all SRU are subject to the refinery NSPS. Therefore, the MACT floor for the control of HAP emission from the SRU vents is based on the emission reductions achieved by facilities subject to the NSPS for petroleum refineries.

The EPA is aware that there are significant process differences between the Claus sulfur units and the non-Claus units. At this time, the EPA does not have adequate data to characterize the HAP emissions from these non-Claus sulfur units but available data indicate that these units are likely operating at emission levels that meet the MACT floor criteria. The EPA is requesting comment on these processes and, based on the new information, will reexamine the possible need to set a separate standard for these few non-Claus SRU.

The refinery NSPS outlines two options for the control of emissions from SRU: (1) For oxidative control systems or reductive control systems followed by incineration, the emission limit is 250 ppmv of SO_2 at zero percent excess air; and (2) for reductive control systems not followed by incineration, the emission limit is 300 ppmv of reduced sulfur compounds and 10 ppmv of H_2S, each calculated as ppmv SO_2 at zero percent excess air. The second option translates well into a HAP emission limit because TRS compounds are defined as H_2S, COS, and CS_2. The fact that H_2S is a component of the TRS and cannot exceed 10 ppmv suggests that the COS and CS_2 (i.e., the HAP) are at least 290 ppmv and at most 300 ppmv. The first option is not easily translated into a HAP emission limit (i.e., there is no direct way to determine the contribution of H_2S, a non-HAP, to the total limit), but it suggests that use of an oxidation control system or incineration effectively controls emissions of TRS. Therefore, it is concluded that the MACT floor for the SRU vent is a combined HAP or TRS emission limit of 300 ppmv measured as ppmv SO_2 at zero percent excess air. It is important to note that the EPA is still in the process of collecting and validating additional data for both the Claus and non-Claus SRU and will re-evaluate and possibly revise the floor determination based on the new data.

(2) MACT floor determination for new SRU/sulfur plant vents. Based on the limited information and data available, EPA concluded that the MACT floor determination for existing SRU sources of HAP (i.e., the 300 ppmv HAP emission limit derived from the refinery NSPS) also represents the HAP emission control that is achieved by the best-controlled similar source in the source category. Therefore, the MACT floor for new SRUs is the same as the MACT floor for existing SRUs. No options have been identified for this source that would provide a level of control more stringent that the MACT floor.

D. Selection of Monitoring Requirements

The EPA evaluated the hierarchy of monitoring options available for this source category. The EPA identified and analyzed several different monitoring options taking into consideration the various unit operations, the HAP emitted, and the proposed control equipment for each of the respective vents. This hierarchy includes measurement of HAP (e.g., HCl) by a CEMS, installation of measurement devices for continuous monitoring of process and/or control device operating parameters, and periodic or one-time performance tests. Each option was evaluated relative to its technical feasibility, cost, ease of implementation, and relevance to the process or control device.

A CEMS provides a direct measurement of emissions. For this source category, CEMS are commercially available for a number of the pollutants of concern, e.g., HCl, CO, metallic HAP/PM, and TRS compounds. However, it is important to note that for some of these systems the technical feasibility of monitoring the unit operations that comprise the source category has not yet been demonstrated. There also are other concerns. For example, the EPA believes that HCl monitors can be used for CRU catalyst regeneration vent applications and TRS monitors can be used for SRU vent COS and CS_2 emissions; but the nationwide capital cost of this option (CEMS for all reformer unit HCl scrubbers and sulfur plants) is estimated at $18.5 million for the HCl monitors and $6.1 million for the TRS monitors, with annual costs of $14.2 million and $4.3 million, respectively, for operation and maintenance, quality assurance and quality control performance evaluation, and reporting/recordkeeping requirements. Because of the high cost of using CEMS compared with the costs of the emission control devices and the cost of monitoring control device and process parameters, the EPA is not requiring the blanket use of CEMS to demonstrate compliance for this source category. However, CEMS for CO are included as an alternative under the proposed rule for affected CCU. These devices are commonly used to monitor CCU process operations and are also required under the refinery NSPS. The cost associated with continuous CO monitors is considered reasonable. Although CEMS are not required, the proposed rule does provide the owner or operator a general option of installing and operating a CEMS and complying with most of the requirements in the general provisions that apply to a CEMS.

Another option for compliance assurance is monitoring process and/or control device operating parameters plus conducting routine (e.g., annual) emission tests. With the exception of complete burn/combustion CCUs, process parameters were not selected as indicators for HAP emissions for the unit operations in this source category because an adequate correlation does not exist between production or process parameters and emission rates. Control device operating parameters were selected instead because the EPA's experience has shown that measurements outside a specified range of values, for example established during an initial performance test, could be used to indicate the control device was not operating properly. The estimated nationwide capital costs of this option are $7.4 million; annual costs are $10.6 million for all three vents in the source category. Note that the periodic emission tests required for these vents (for example testing using Method 26A in appendix A to 40 CFR part 60 for HCl emissions from CRU) would not require a capital investment. The estimated cost assumes the use of a test contractor and includes time for participation by plant personnel.

The EPA believes that reasonable assurance of compliance is achieved through the combination of continuous emission monitoring, process and control device operating parameter monitoring, and the periodic emission testing required in the proposed rule. The proposed rule requires that each owner or operator of a CCU, CRU, or SRU using a combustion device to limit HAP emissions must monitor temperature as a control device operating parameter. The owner or operator of a CCU using an ESP for control of metallic HAP emissions must monitor the voltage and secondary current of the control device or the total power input. If a wet scrubber is used to comply with the requirements for metallic HAP or HCl control, the owner or operator must monitor the pressure drop across the scrubber, the gas and water flow rate to the scrubber, and determine the liquid-to-gas ratio. If new information is obtained after proposal indicating the use or planned use of dry scrubbers, appropriate monitoring provisions will be included in the final rule. For CCU subject to the rule, such as complete burn/combustion CCU, that do not use add-on control devices, the owner or operator must continuously monitor the concentration of CO emissions from the unit or measure the regeneration process operating temperature and the oxygen content of the vent gas. An owner or operator may request approval to monitor parameters other than those listed above by submitting a request to the applicable permitting authority. The EPA is soliciting comment on appropriate monitoring parameters for CRU that do not use an external scrubber to control HCl emissions.

V. Summary of Impacts of Proposed Standards

A. Air Quality Impacts

The impacts presented in this section include the process vent emissions from all three of the unit operations listed in the source category. The EPA estimates nationwide HAP emissions from process vents on these unit operations at approximately 7,270 Mg/yr (8,000 tpy) at the current level of control. The proposed standards will reduce nationwide HAP emissions by about 5,960 Mg/yr (6,560 tpy), an 82 percent reduction. Emissions of VOC, CO, and PM (mainly from CCUs), and emissions of H_2S (mainly from SRUs) would be reduced by about 65 percent from the current level of about 185,900 Mg/yr (204,500 tpy). Little or no adverse secondary air impacts, water or solid waste impacts are anticipated from the implementation of these standards.

B. Cost Impacts

Nationwide capital and annualized costs of control equipment are estimated at $179 million and $35.5 million/yr, respectively. The implementation of this regulation is expected to result in an overall annual national cost of $53.5 million. This includes a cost of $43.7 million for operation/maintenance of control devices and a monitoring, recordkeeping, and reporting cost of $9.8 million.

C. Economic Impacts

The economic impact analysis for the selected regulatory alternatives shows that the estimated price increase of refined petroleum products is 0.24 percent for the 127 refineries expected to incur compliance costs as a result of the rule. The estimated decrease in output is 0.17 percent of domestic refinery products. The decline in domestic production is due to higher imports and reduced quantity demanded due to higher prices. However, the value of domestic shipments is expected to increase by 0.07 percent because the estimated price increase more than offsets the lower production volume. Annual net exports (exports minus imports) are predicted to decrease by 0.76 percent. Employment in the industry is likely to decrease by 0.19 percent (136 jobs). No plant closures or significant regional impacts are expected. For more information on the economic impact analysis methodology and results, consult the ''Economic Impact Analysis for the Petroleum Refinery NESHAP.'' (See Docket Item II–A–5.)

D. Non-air Health and Environmental Impacts

The proposed NESHAP are based on air pollution control systems which are currently in use in the industry. The proposed NESHAP would reduce emissions of HAP and ambient pollutants, and consequently, occupational exposure levels for plant employees may be lowered.

E. Energy Impacts

The national electric usage required to comply with the rule is expected to increase by about 114,000 MW/hr, primarily for CCU PM and CO controls and SRU incinerators. National natural gas usage, primarily for SRU incinerators, is expected to increase by about 1.5 billion cubic feet. Water usage for CRU scrubbers, is expected to increase by about 6.2 million gallons nationwide.

VI. Request for Comments

The EPA seeks full public participation in arriving at its final decisions and encourages comments on all aspects of this proposal from all interested parties. Full supporting data and detailed analysis should be submitted with comments to allow the EPA to make use of the comments. All comments should be directed to the Air and Radiation Docket and Information Center, Docket No. A–97–36 (see **ADDRESSES**). Comments on this document must be submitted on or before the date specified in **DATES**.

Commentors wishing to submit proprietary information for consideration should clearly distinguish such information from other comments and clearly label it ''CBI.'' Submissions containing such proprietary information should be sent directly to the following address, and not to the public docket, to ensure that proprietary information is not inadvertently placed in the docket: Attention: Mr. Bob Lucas, c/o Ms. Melva Toomer, U.S. EPA Confidential Business Information Manager, OAQPS (MD–13), Research Triangle Park, NC 27711. Information covered by such a claim of confidentiality will be disclosed by the EPA only to the extent allowed and by the procedures set forth in 40 CFR part 2. If no claim of confidentiality accompanies the submission when it is received by the EPA, it may be made available to the public without further notice to the commentor.

The EPA specifically requests comments on seven topics where additional information is desired prior to promulgation. As discussed below, topics entail: Emission characteristics and operation of non-fluidized CCU and non-Claus SRU; HAP emissions from SRU sulfur pits; excess emissions from CCU resulting from maintenance/repair of the control device; potential subcategorization of CCU; selection of a cutoff value for CRU depressuring/ purging operations; appropriate monitoring parameters for CRU with internal scrubbing systems; and consideration of an alternative format for the proposed Ni emission limit.

A. Non-fluidized Catalytic Cracking Units and Non-Claus Sulfur Recovery Units

As discussed in section II.D.1 of this document, non-fluidized CCU (accounting for only 2.9 percent of the total catalytic cracking process charge rate), were operated by 7 refineries in 1997. Although the exact number of non-Claus SRU is not known, Claus SRU represent 96 percent of the SRU in the EPA database. While the EPA observed a small number of non-fluid CCU and non-Claus SRU in operation, little or no test data are available to determine differences in emissions and operation as compared to fluidized-bed CCU or Claus SRU. The EPA requests information and data on control status, operating processes, and emission measurements using EPA methodology. Based on this information and data, the EPA will determine whether a separate emission limit is warranted for non-fluidized bed CCU or non-Claus SRU and analyze the associated impacts of control. Based on these analyses, the EPA may retain the proposed standard with no distinction between the processes, include a separate standard in the final rule, or determine that no standard is warranted for one or both of these subcategories.

B. Potential Emission Sources

Process observations during plant site visits indicate that SRU sulfur recovery pits and certain types of tail gas treatment units may be potential HAP emission sources. Emissions from sulfur pits occur at each SRU reactor when elemental sulfur is condensed and removed from the SRU gas and the liquid sulfur is collected and stored in bins. Several refineries are known to purge the sulfur pits to prevent the buildup of explosive levels of gases. Emissions are controlled by combining the purged gases from the pits with the SRU or tail gas treatment unit off-gas and venting to an incinerator. Certain types of tail gas treatment units, such as ''Stretford'' units, employ a series of open vessels as part of the solution circulation loop and a direct air contact cooling tower to cool the solution. Limited data indicate that HAP emissions are released from the solution tank and direct air contact cooling towers. The EPA specifically requests information and data on these process operations, emissions, and control practices. Based on analyses of the information and data received, the EPA may consider regulation of these sources when developing the final rule.

C. Catalytic Cracking Unit Control Device Maintenance

The Agency requests comment on the need for allowing operation of CCU when control devices such as boilers or venturi scrubbers are out of service for maintenance overhauls. Information is specifically requested on the number of facilities which have this need, current maintenance practices for boilers and scrubbers, their frequency and length, safety considerations, and manufacturer's recommendations. Should monitoring by other methods be required during such a period? Should time limits be applied? Would more frequent, periodic preventative maintenance, such as that envisioned by the maintenance plan included in the proposed standard preclude or lessen the need for 2 year or 10-year overhauls? How should the EPA provide operational flexibility while ensuring that emissions are minimized and good air pollution control practices are followed? The EPA will use comments, information, and suggestions received to address this issue in the final rule.

D. Subcategorization of Catalytic Cracking Units

As discussed in section IV.C.1 of this document, the EPA recognizes the potential need for CCU subcategorization due to the wide variety of process variations. For this reason, additional information and data on CCU processes, emissions, and distinguishing characteristics that meet subcategorization criteria are requested. Based on the information and data received, the EPA will consider whether separate standards for different CCU processes are warranted.

E. Catalytic Reforming Unit Depressuring/Purging Cutoff Value

Under the proposed standards, CRU control requirements do not apply to depressuring or purging operations at a differential pressure between the gas transfer system to the control device of less than 1 psig. The EPA evaluated several different approaches to deriving the cutoff value, but selected an approach based on differential pressure due to the concern that an absolute value would not be appropriate for all plants due to process variations. Because differential pressure may be more difficult to monitor, EPA also included a cutoff of 1 psig, consistent with State rules, for the reactor vent pressure. Comments, information, and data on outlet unit pressures for depressuring/purging and the feasibility of establishing a differential value are requested. The EPA will evaluate the data and information received and address this issue in the final rule.

F. Monitoring of Catalytic Reforming Units with Internal Scrubbing Systems

As previously noted the MACT floor for CRU catalyst regeneration vents is established based on current industry practices in use and control equipment in place at CRU. Two classes of scrubbers were designated to characterize the groups of scrubbers used to control emissions from CRU catalyst regeneration vents during the coke burn-off step, single stage and multiple stage scrubbers. Each of these scrubber classes can be further categorized as either a scrubber that is internal to the process (e.g., caustic injection) or external to the process (e.g., a packed tower). Because the internal type scrubbers are contained within the process units itself, there is no convenient scrubber operating parameter that can be monitored as is the case with an external scrubber. The EPA is therefore requesting comment on identification of appropriate monitoring parameters for the internal type CRU scrubbing systems. For example, would use of a simplified monitoring system (such as colorimetric tubes) be adequate to demonstrate that the acid gases in the unit are sufficiently controlled. Or, would monitoring of the recycle stream within the unit rather than the exhaust gas be adequate to characterize the scrubber performance.

G. Alternative CCU Standard

The EPA is considering the addition of a third alternative standard to reduce metal HAP emissions from the CCU regeneration vent. The current proposal requires compliance with either a PM limit of 1.0 lb/1,000 lbs of coke burn-off, or a Ni limit of 0.029 lb/hr. Industry representatives have requested inclusion of a metal HAP (or Ni) emission limit formatted in terms of lb of metal HAP (or Ni)/1,000 lbs of coke burn-off. The EPA requests comments on the need and benefits of a third alternative. The EPA will consider all regulatory formats. Commenters suggesting a particular emission limit should explain how the limit correlates to the MACT floor.

From the beginning of this project, the EPA has recognized that the format for the CCU standard was a significant issue. During initial discussions with stakeholders, including early site visits to refineries, EPA asked for thoughts on possible formats. Also, from the beginning, regulatory alternatives have included the use of PM as a surrogate for total metal HAP.

Using the PM format established by NSPS Subpart J, the MACT floor determination set the standard at 1.0 lb/1,000 lbs of coke burn-off as characterizing performance of the MACT floor technology. An early draft of the regulation included a second alternative that provided a Ni emission limit of 0.00047 lb Ni/1,000 lbs of coke burn-off. This second alternative was derived from the first alternative by using the average Ni concentration in the CCU catalyst regeneration fines to convert the PM mass to an equivalent Ni mass. These fines consist of the PM that is collected by the air pollution control device following the CCU regeneration vent.

Upon review of this draft regulation, representatives of small refineries commented that the format of both regulatory alternatives then under consideration was independent of unit size or throughput. Therefore, both alternatives, expressed in terms of coke burn-off, penalized small CCU. Representatives cited examples of small units with very low annual Ni emissions (in terms of tons per year) which would not be in compliance with either regulatory alternative. In response, the EPA revised the draft regulation by changing the format of the Ni standard to a lb/hr format, while keeping the PM limit expressed in terms of coke burn-off. The second alternative in the current proposal provides a Ni limit of 0.029 lb/hr. Industry representatives supported the new format, while also requesting that the previous format be included as a third alternative.

Industry representatives have recommended that the third alternative be set at 0.007 lb of Ni/1,000 lbs of coke burn-off to account for the highest Ni concentrations found in CCU feed streams and to account for the variability in the crude oil. The API/NPRA recommended Ni standard is, in their view, technically equivalent to the floor. Documents relating to the API/NPRA recommendation are in the docket for this rulemaking.

Since the time of EPA's original suggestion for this format, EPA has continued to collect data on the Ni concentration in CCU fines. The current data base shows that an alternative based on average Ni fines concentration could be set at 0.0013 lb of Ni/1,000 lbs of coke burn-off. The EPA is continuing to evaluate the API/NPRA recommendation.

The EPA is requesting comments on providing a third regulatory alternative. The alternative could be based on metal HAP (or Ni) emissions in terms of lb/1,000 lbs of coke burn-off, or it could have a different format. The alternative must be technically equivalent to the MACT floor. Specifically, the Agency requests comments regarding: (1) The need for and usefulness of a third alternative for specific refineries, (2) the use of Ni concentrations as a surrogate for total metal HAP, and (3) the use of the arithmetic mean, median, geometric mean, 90th percentile value, 95th percentile value, or highest value as the representative concentration used in the factor for conversion of PM to Ni.

H. Overlap With New Source Performance Standard

As discussed in section III.A of this document, the EPA recognizes that some fluidized-bed CCU and SRU are subject to NSPS and related Title I requirements. To minimize the burden of duplicative rule requirements, the proposed MACT standard includes provisions allowing compliance demonstrations for the NSPS requirements (which govern criteria pollutants) to serve as compliance demonstrations for the HAP emission control requirements. The intent of these provisions is to minimize duplication without reducing or changing the Title I requirements. The EPA requests comments on the adequacy of this approach, together with suggestions for other approaches that would achieve this goal.

I. Status of an Exceedance or Excursion

Section 63.1565(p) of the proposed standard provides that more that one exceedance or excursion by the same control device during a semi-annual reporting period is a violation. This provision is included in the proposed standard to maintain consistency with the earlier MACT standard for petroleum refineries in 40 CFR part 63, subpart CC. The EPA is further considering this proposed provision and its impacts. However, EPA currently does not have adequate information on the long-term performance of the MACT emission control technologies for the affected processes and their ability to continuously achieve compliance. For this reason, EPA requests additional information and data relative to control device performance. Based on the information received, EPA will decide whether to permit facilities to have an exceedance or excursion once per semi-annual reporting period.

VII. Administrative Requirements

A. Docket

The docket is an organized and complete file of all the information considered by the EPA in the development of this rulemaking. The docket is a dynamic file, because material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can effectively participate in the rulemaking process. Along with the proposed and promulgated standards and their preambles, the contents of the docket will serve as the record in the case of judicial review. (See CAA section 307(d)(7)(A).)

B. Public Hearing

A public hearing will be held, if requested, to discuss the proposed standards in accordance with section 307(d)(5) of the Act. If a public hearing is requested and held, the EPA will ask clarifying questions during the oral presentation but will not respond to the presentations or comments. Written statements and supporting information will be considered with equivalent weight as any oral statement and supporting information subsequently presented at a public hearing. Persons wishing to attend or to make oral presentations or to inquire as to whether a hearing is to be held should contact the EPA (see **FOR FURTHER INFORMATION CONTACT**). To provide an opportunity for all who may wish to speak, oral presentations will be limited to 15 minutes each.

Any member of the public may file a written statement on or before November 10, 1998. Written statements should be addressed to the Air and Radiation Docket and Information Center (see **ADDRESSES**), and refer to Docket A–97–36. A verbatim transcript of the hearing and written statements will be placed in the docket and be available for public inspection and copying, or be mailed upon request, at the Air and Radiation Docket and Information Center.

C. Executive Order 12866

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the EPA must determine whether the regulatory action is ''significant'' and therefore subject to review by the Office of Management and Budget (OMB), and the requirements of the Executive Order. The Executive Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligation of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this regulatory action is not ''significant'' because none of the listed criteria apply to this action. However, OMB has classified this rule as potentially significant and has requested review. Consequently, this action will be submitted to OMB for review under Executive Order 12866.

D. Enhancing the Intergovernmental Partnership Under Executive Order 12875

In compliance with Executive Orders 12875, the EPA involved State regulatory experts in the development of this proposed rule. No tribal governments are believed to be affected by this proposed rule. State and local governments are not directly impacted by the rule, i.e., they are not required to purchase control systems to meet the requirements of the rule. However, they will be required to implement the rule; e.g., incorporate the rule into permits and enforce the rule. They will collect permit fees that will be used to offset the resources burden of implementing the rule. Comments have been solicited from States and have been carefully considered in the rule development process. In addition, all States and tribal governments are encouraged to comment on this proposed rule during the public comment period, and the EPA intends to fully consider these comments in the development of the final rule.

E. Unfunded Mandates Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 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, the 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 to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires the 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 the 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 the EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed pursuant to 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.

The EPA has determined that this rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, or tribal governments, in the aggregate, or the private sector in any one year. Thus, today's rule is not subject to the requirements of sections 202 and 205 of UMRA. In addition, the EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments or impose obligations upon them. Therefore, today's rule is not subject to the requirements of section 203 of the UMRA.

F. Executive Order 13045

Executive Order 13045, ''Protection of Children from Environmental Health and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that EPA determines: (1) ''Economically significant'' as defined under E.O. 12866, and (2) the environmental health or safety risk addressed by the rule has 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 preferrable to other potentially effective and reasonable feasible alternatives considered by the Agency. This proposed rule is not subject to E.O. 13045 because it does not involve decisions on environmental health risks or safety risks that may disportionately affect children.

G. Regulatory Flexibility

The Regulatory Flexibility Act (RFA) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements 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 business, small not-for-profit enterprises, and small governmental jurisdictions.

In developing these proposed standards, the EPA has worked with industry trade groups to identify the special concerns of small refineries. Site visits also were conducted to five small refineries where the EPA met with facility representatives and listened to their concerns. In response, the EPA has exercised the maximum degree of flexibility in minimizing impacts on small business through the alternative Ni standard and subcategorization of the source category for CRU vents. Also, these proposed standards, which are based on MACT-floor level control technology, reflect the minimum level of control allowed under the Act.

The EPA economic analysis identified 16 small businesses that operate a total of 19 refineries. Two of these refineries operated by two different firms are expected to incur compliance costs and the remaining 17 refineries are not expected to incur any compliance costs as a result of the proposed NESHAP. Annual compliance costs for the two affected refineries would be less than one percent of estimated sales revenues. Additional information is included in chapter 6 of the economic impact analysis for the proposed standards. (See Docket Item II–A–5.)

Based on this information, the EPA has concluded that this proposed rule would not have a significant economic impact on a substantial number of small entities. Therefore, I certify that this action will not have a significant economic impact on a substantial number of small entities.

H. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to OMB under the requirements of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* An Information Collection Request (ICR) document has been prepared by EPA (ICR No. 1844.01), and a copy may be obtained from Sandy Farmer, OPPE Regulatory Division, U.S. Environmental Protection Agency (2137), 401 M Street SW, Washington, DC 20460, or by calling (202) 260–2740.

The proposed information requirements include mandatory notifications, records, and reports required by the NESHAP general provisions (40 CFR part 63, subpart A). These information requirements are needed to confirm the compliance status of major sources, to identify any nonmajor sources not subject to the standards and any new or reconstructed sources subject to the standards, to confirm that emission control devices are being properly operated and maintained, and to ensure that the standards are being achieved. Based on the recorded and reported information, the EPA can decide which plants, records, or processes should be inspected. These recordkeeping and reporting requirements are specifically authorized under section 114 of the Act (42 U.S.C. 7414). All information submitted to the EPA for which a claim of confidentiality is made will be safeguarded according to Agency policies in 40 CFR part 2, subpart B. (See 41 FR 36902, September 1, 1976; 43 FR 39999, September 28, 1978; 43 FR 42251, September 28, 1978; and 44 FR 17674, March 23, 1979.)

The annual public reporting and recordkeeping burden for this collection of information (averaged over the first 3 years after the effective date of the rule) is estimated to total 18,581 labor hours per year at a total annual cost of $597,007/yr. This estimate includes certain notifications which are streamlined to incorporate notifications of applicability for existing sources, results of initial performance tests (including repeat performance tests where needed), and monitoring information. The estimates also include one-time preparation of a startup, shutdown, and malfunction plan; semi-annual reports of any period of excess emissions; and recordkeeping. Reporting requirements have been streamlined to allow the owner or operator to report only those events where the procedures in the startup, shutdown, and malfunction plan were not followed in the semi-annual excess emissions report. Total capital costs associated with monitoring requirements over the 3-year period of the ICR is estimated at $463,000/yr; this estimate includes the capital and startup costs associated with installation of monitoring equipment. The total operation and maintenance cost is estimated at $4,418,500/yr.

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 purpose of collecting, validating, and verifying information; process and maintain information and disclose and provide information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to respond to a collection of information; search existing 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 the EPA's regulations are listed in 40 CFR part 9 and 48 CFR Chapter 15.

Comments are requested on the Agency's need for this information, the accuracy of the burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques. Send comments on the ICR to the Director, OPPE Regulatory Information Division; U.S. Environmental Protection Agency (2136), 401 M Street SW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, marked ''Attention: Desk Officer for EPA.'' Include the ICR number in any correspondence. Because OMB is required to make a decision concerning the ICR between 30 and 60 days after September 11, 1998, a comment to OMB is best assured of having its full effect if OMB receives it by October 13, 1998. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

I. Pollution Prevention Act

During the development of the proposed NESHAP, the EPA explored opportunities to eliminate or reduce emissions by substitution of non-HAP for HAP-generating materials. One potential approach is the use of a non-chlorinated catalyst material for CRUs. However, available information are insufficient to evaluate the feasibility or research status of this potential approach. The EPA will continue to work with the industry to collect information on the potential use of different CRU catalyst materials and encourage new research on this approach. The pollution prevention concept is incorporated in the proposed alternative Ni emission standard which encourages the use of feed with lower metallic HAP content. Also, facilities which hydrotreat to remove metals from the feed can meet the proposed standard with a less effective PM control device.

J. National Technology Transfer and Advancement Act

Under section 12(d) of the National Technology Transfer and Advancement Act (NTTA), Pub. L. 104–113 (March 7, 1996), the Agency is required to use voluntary consensus standards in its regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices, etc.) which are adopted by voluntary consensus standard bodies. Where available and potentially applicable voluntary consensus standards are not used by the Agency, the Act requires the Agency to provide Congress, through OMB, an explanation of the reasons for not using such standards. This section summarizes the Agency's response to the requirements of the NTTA for the analytical test methods proposed as part of today's standards.

The proposed standard includes test methods and procedures for the purpose of emission tests needed to demonstrate initial compliance. Although a vast array of test methods and procedures applicable to petroleum content and material specifications are published by the American Society of Testing and Materials, these methods are not applicable to determining the volume and type of air emissions from the affected sources. To facilitate the emission testing process and associated costs, the proposed standards uses surrogates for the HAPs included in emissions from the affected sources. This approach allows use of the conventional test methods required by the existing NSPS which have been in use by EPA, States, and three-quarters of the industry for over 20 years. Alternative test methods also may be used subject to EPA approval. In addition, the EPA worked with industry experts to revise the NSPS procedure for determining the coke burn-off rate. The amended procedure utilizes common industry practice for determining the rate, corrects a technical equation error in the older NSPS, and reduces costs by allowing the use of existing data rather than daily stack tests to obtain needed data.

K. Clean Air Act

In accordance with section 117 of the Act, publication of this proposal was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. This regulation will be reviewed 8 years from the date of promulgation. This review will include an assessment of such factors as evaluation of the residual health risks, any overlap with other programs, the existence of alternative methods, enforceability, improvements in emission control technology and health data, and the recordkeeping and reporting requirements.

L. Executive Order 13084

Under Executive Order 13084, EPA may not issue a regulation that is not required by statute, that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments. If the mandate is unfunded, EPA must provide to the Office of Management and Budget, in a separately identified section of the preamble to the rule, a description of the extent of EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires EPA to develop an effective process permitting elected and other representatives of Indian tribal governments to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities. Today's rule does not significantly or uniquely affect the communities of Indian tribal governments. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Petroleum refineries, Reporting and recordkeeping requirements.

Dated: August 25, 1998.

Carol M. Browner,

Administrator.

For the reasons set out in the preamble, part 63 of title 40, chapter I, of the Code of Federal Regulations is proposed to be amended as follows:

PART 63—[AMENDED]

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

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

* * * * *

2. Part 63 is amended by adding subpart UUU to read as follows:

Subpart UUU—National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries—Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plants

Sec.

Subpart UUU—National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries—Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plants

§ 63.1560 Applicability and designation of affected sources.

(a) The provisions of this subpart apply to the owner or operator of each new and existing catalytic cracking unit, catalytic reforming unit, and sulfur recovery plant unit associated with a petroleum refinery and located at a major source of hazardous air pollutants (HAP) as defined in § 63.2 of this part.

(b) Affected sources at a facility subject to this subpart are:

(1) The process vent or group of process vents on each fluidized and other (i.e., non-fluidized) catalytic cracking unit, that is associated with regeneration of the catalyst used in the unit (i.e., the catalyst regeneration flue gas vent);

(2) The process vent or group of process vents, on each catalytic reforming unit (including but not limited to semi-regenerative, cyclic, or continuous processes), that is associated with regeneration of the catalyst used in the unit. This affected source includes vents that are used during the unit depressurization, purging, coke burn, catalyst rejuvenation, and reduction or activation purge; and

(3) The process vent or group of process vents, that vents from a Claus or other sulfur recovery plant unit or the tail gas treatment unit serving the sulfur recovery plant, that is associated with sulfur recovery.

(c) This subpart does not apply to gaseous streams routed to a fuel gas system.

(d) An owner or operator of a fluidized-bed catalytic cracking unit catalyst regenerator subject to and in compliance with the standard for particulate matter emissions in § 60.102 of this chapter and all associated requirements (including but not limited to testing, monitoring, recordkeeping, and reporting provisions) is considered to be in compliance with the standard in § 63.1562(a)(1) of this subpart and all associated requirements. An owner or operator of a fluidized-bed catalytic cracking unit catalyst regenerator subject to and in compliance with the standard for carbon monoxide in § 60.103 of this chapter and all associated requirements (including but not limited to testing, monitoring, recordkeeping, and reporting provisions) is considered to be in compliance with the standard in § 63.1562(a)(2) of this subpart and all associated requirements. An owner or operator of a sulfur recovery unit subject to and in compliance with the standard for sulfur oxides in § 60.104 of this chapter and all associated requirements (including but not limited to testing, monitoring, recordkeeping, and reporting provisions) is considered to be in compliance with the standard in § 63.1562(c) of this subpart and all associated requirements.

§ 63.1561 Definitions.

All terms used in this subpart shall have the meaning given them in the Clean Air Act, in subpart A of this part, and in this section. If the same term is defined in subpart A and in this section, it shall have the meaning given in this section for purposes of this subpart.

Catalytic cracking unit means a refinery process unit in which petroleum derivatives are charged; hydrocarbon molecules in the presence of a catalyst are fractured into smaller molecules, or react with a contact material to improve feedstock quality for additional processing; and the catalyst or contact material is regenerated by burning off coke and other deposits. The unit includes, but is not limited to 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.

Catalytic cracking unit regenerator means one or more regenerators (multiple regenerators) which comprise that portion of the catalytic cracking unit in which coke burn-off and catalyst or contact material regeneration occurs, and includes the regenerator combustion air blower(s).

Catalytic reforming unit means a refinery process unit that reforms or changes the chemical structure of naphtha into higher octane aromatics through the use of a metal catalyst and chemical reactions that include dehydrogenation, isomerization, and hydrogenolysis. The catalytic reforming unit includes the reactor, regenerator (if separate), separators, catalyst isolation and transport vessels (e.g., lock and lift hoppers), recirculation equipment, scrubbers, and other ancillary equipment.

Catalytic reforming unit regenerator means one or more regenerators which comprise that portion of the catalytic reforming unit in which the following regeneration steps typically are performed: Depressurization, purge, coke burn-off, catalyst rejuvenation with a chloride (or other halogenated) compound(s), and a final purge. The catalytic reforming unit catalyst regeneration process can be conducted either as a semi-regenerative, cyclic, or continuous regeneration process.

Coke burn-off means the coke removed from the surface of the catalytic cracking unit catalyst or the catalytic reforming unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 63.1566 (Test methods and procedures) of this subpart.

Combustion device means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the destruction of organic hazardous air pollutants or volatile organic compounds.

Combustion zone means the space in an enclosed combustion device (e.g., vapor incinerator, boiler, furnace, or process heater) occupied by the organic HAP and any supplemental fuel while burning. The combustion zone includes any flame that is visible or luminous as well as that space outside the flame envelope in which the organic HAP continues to be oxidized to form the combustion products.

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

Continuous regeneration reforming means a catalytic reforming process characterized by continuous flow of catalyst material through a reactor where it mixes with feedstock in a counter-current direction, and a portion of the catalyst is continuously removed and sent to a special regenerator where it is regenerated and continuously recycled back to the reactor.

Control device means any equipment used for recovering, removing, or oxidizing HAP in either gaseous or solid form. Such equipment includes, but is not limited to, condensers, scrubbers, electrostatic precipitators, incinerators, flares, boilers, and process heaters.

Cyclic regeneration reforming means a catalytic reforming process characterized by continual batch regeneration of catalyst in situ in any one of several reactors (e.g., four or five separate reactors) that can be isolated from and returned to the reforming operation, while maintaining continuous reforming process operations (i.e., feedstock continues flowing through the remaining reactors without change in feed rate or product octane).

Flame zone means the portion of a combustion chamber of a boiler or process heater occupied by the flame envelope created by the primary fuel.

Flow indicator means a device that indicates whether gas is flowing, or whether the valve position would allow gas to flow, in a line.

HCl means, for the purposes of this subpart, gaseous emissions of hydrogen chloride that serve as a surrogate measure for total emissions of hydrogen chloride and chlorine as measured by Method 26A in appendix A to part 60 of this chapter or an approved alternative method.

Incinerator means an enclosed combustion device that is used for destroying organic compounds, with or without heat recovery. Auxiliary fuel may be used to heat waste gas to combustion temperatures.

Ni means, for the purposes of this subpart, particulate emissions of nickel that serve as a surrogate measure for total emissions of metal HAPs, including but not limited to: Antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium as measured by Method 29 in appendix A to part 60 of this chapter or by an approved alternative method.

Petroleum refinery means an establishment/installation primarily engaged in petroleum refining as defined in the Standard Industrial Classification (SIC) code for petroleum refining (SIC 2911), and used primarily for:

(1) Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;

(2) Separating petroleum; or

(3) Separating, cracking, reacting, or reforming an intermediate petroleum stream, or recovering a by-product(s) from the intermediate petroleum stream (e.g., sulfur recovery).

PM means, for the purposes of this subpart, emissions of particulate matter that serve as a surrogate measure of the total emissions of particulate matter and metal HAPs contained in the particulate matter, including but not limited to: Antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, maganese, nickel, and selenium as measured by Methods 5B or 5F in appendix A to part 60 of this chapter or by an approved alternative method.

Process heater means an enclosed combustion device that primarily transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

Semi-regenerative reforming means a catalytic reforming process characterized by shutdown of the entire reforming unit (e.g., which may employ three to four separate reactors) at specified intervals or at the owner's or operator's convenience for in situ catalyst regeneration.

Sulfur recovery unit means a process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide. This definition does not include a unit where the modified reaction is carried out in a water solution which contains a metal ion capable of oxidizing the sulfide ion to sulfur, e.g., the LO–CAT II process.

TRS means, for the purposes of this subpart, emissions of total reduced sulfur compounds, expressed as an equivalent sulfur dioxide concentration, that serve as a surrogate measure of the total emissions of sulfide HAPs carbonyl sulfide and carbon disulfide as measured by Method 15 in appendix A to part 60 of this chapter or by an approved alternative method.

TOC means, for the purposes of this subpart, emissions of total organic compounds excluding methane and ethane that serve as a surrogate measure of the total emissions of organic HAP compounds, including but not limited to acetaldehyde, benzene, hexane, phenol, toluene, and xylenes and non-HAP volatile organic compounds as measured by Method 18 or Method 25A in appendix A to part 60 of this chapter or an approved alternative method.

§ 63.1562 Emission standards for existing sources.

(a) *Catalytic cracking unit regeneration.* The owner or operator of a catalytic cracking unit shall comply with the standards in paragraphs (a)(1)(i) or (a)(1)(ii) of this section and the standard in paragraph (a)(2) of this section.

(1) The owner or operator shall identify the standard selected in the notification of compliance status report as required by § 63.1567(a)(6) of this subpart. Following any 6-month reporting period, the owner or operator may change the standard selected for compliance by submitting a request to the applicable permitting authority containing the information specified in § 63.1567(b)(7) of this subpart.

(i) Emissions of PM shall not exceed 1.0 kilogram (kg)/1,000 kg [1.0 pound (lb)/1,000 lb] of coke burn-off in the catalyst regenerator; or

(ii) Emissions of nickel (Ni) from the catalyst regenerator vent on each catalytic cracking unit shall not exceed 13,000 milligrams/hour (mg/hr) [0.029 pound per hour (lb/hr)].

(2) The concentration of carbon monoxide (CO) exiting the catalyst regenerator vent or CO boiler (if a CO boiler is used as the combustion device) shall not exceed 500 parts per million (ppm) by volume (dry basis).

(b) *Catalytic reforming unit regeneration.* The owner or operator of a catalytic reforming unit shall comply with paragraphs (b)(1) through (b)(3) of this section.

(1) During depressurization and purging, comply with the requirements in paragraphs (b)(1)(i) or (b)(1)(ii) of this section.

(i) The owner or operator shall vent TOC emissions from the regenerator to a flare that meets the requirements for control devices in § 63.11(b) of this part; or

(ii) The owner or operator shall reduce uncontrolled emissions of TOC using a control device, by 98 percent by weight or to a concentration of 20 ppm by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent. If a boiler or process heater is used to comply with the percent reduction requirement or concentration limit, the vent stream shall be introduced into the flame zone, or any other location that will achieve the required percent reduction or concentration.

(iii) The control device requirements of paragraphs (b)(1)(i) and (b)(1)(ii) of this section do not apply to depressuring and purging operations at a differential pressure between the reactor vent and the gas transfer system to the control device of less than 1 pound per square inch gauge (psig) or if the reactor vent pressure is 1 psig or less.

(2) During coke burn-off and catalyst regeneration, the owner or operator of a semi-regenerative catalytic reforming unit shall reduce uncontrolled emissions of HCl by 92 percent by weight using a control device, or to a concentration of 30 ppm by volume, on a dry basis, corrected to 3 percent oxygen; and

(3) During coke burn-off and catalyst regeneration, the owner or operator of a cyclic or continuous catalytic reforming unit shall reduce uncontrolled emissions of HCl by 97 percent by weight using a control device, or to a concentration of 10 ppm by volume, on a dry basis, corrected to 3 percent oxygen.

(c) *Sulfur recovery units.* The owner or operator of a sulfur recovery unit shall not discharge or cause to be discharged into the atmosphere any emissions of total reduced sulfur (TRS) compounds, expressed as an equivalent sulfur dioxide (SO_2) concentration, in excess of 300 ppm by volume, on a dry basis, at zero percent oxygen.

§ 63.1563 Emission standards for new or reconstructed sources.

(a) *Catalytic cracking unit regeneration.* The owner or operator of a catalytic cracking unit shall comply with the standards for existing affected sources in § 63.1562(a) of this subpart.

(b) *Catalytic reforming unit regeneration.* The owner or operator a catalytic reforming unit shall comply with the standards in paragraphs (b)(1) and (b)(2) of this section.

(1) During depressurization and purging from semi-regenerative processes, comply with the standards for existing affected sources in §§ 63.1562(b)(1)(i) or (b)(1)(ii) of this subpart; and

(2) During coke burn-off and catalyst regeneration, reduce uncontrolled emissions of HCl from semi-regenerative, cyclic, or continuous processes by 97 percent by weight using a control device, or to a concentration of 10 ppm by volume, on a dry basis, corrected to 3 percent oxygen.

(c) *Sulfur recovery units.* The owner or operator shall comply with the standard for existing affected sources in § 63.1562(c) of this subpart.

§ 63.1564 Compliance dates and performance tests.

(a) *Compliance dates.* The owner or operator of a catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit shall demonstrate initial compliance with the requirements of this subpart by the following dates:

(1) [Insert date 3 years following the date of publication date of the final rule in the **Federal Register**] for an existing source unless an extension has been granted by the Administrator as provided in § 63.6(i) of this part.

(2) [Insert date of publication of final rule in the **Federal Register**] or upon initial startup, whichever is later, for a new source that commences construction or reconstruction after September 11, 1998.

(b) *Performance tests—catalytic cracking units.* (1) During the first 150 days following the compliance date, the owner or operator shall conduct a performance test for each new or existing catalytic cracking unit to determine and demonstrate compliance with the PM or Ni emission standard using the test methods and procedures in § 63.1566 of this subpart.

(2) During the first 150 days following the compliance date, the owner or

operator of a new or existing catalytic cracking unit that does not use a combustion device to comply with the CO emission standard and elects to comply with the continuous emission monitoring requirements of § 63.1565(d)(1) of this subpart shall determine and demonstrate compliance according to the following procedures:

(i) The owner or operator shall conduct a performance evaluation of the CO continuous emission monitoring system to determine and demonstrate compliance with the requirements of Performance Specification 4A in appendix B to part 60 of this chapter. The span value shall be 1,000 ppm CO. The performance evaluation shall be conducted according to the procedures in § 63.8(e) of this part.

(ii) Using the continuous emission monitoring system, the owner or operator shall measure and record the average hourly concentration of CO emissions from each catalytic cracking unit during 7 consecutive operating days. The data shall be reduced to 1-hour averages computed from four or more data points equally spaced over each 1-hour period. Compliance is demonstrated where the average hourly concentration is less than or equal to 500 ppm by volume (dry basis).

(3) During the first 150 days following the compliance date, the owner or operator of a catalytic cracking unit that does not use a combustion control device and elects to comply with the operating parameter monitoring requirements of § 63.1565(d)(2) of this subpart, shall conduct a performance test for each unit to determine and demonstrate compliance with the CO emission standard using the test methods and procedures in § 63.1566 of this subpart.

(4) During the first 150 days following the compliance date, the owner or operator of a new or existing catalytic cracking unit that uses a boiler or process heater with a design heat capacity less than 44 megawatts (MW) where the vent stream is not introduced into the flame zone shall conduct a performance test for each unit to determine and demonstrate compliance with the TOC emission standard using the test methods and procedures in § 63.1566 of this subpart.

(c) *Performance tests—catalytic reforming units.* (1) During the first 150 days following the compliance date, the owner or operator of a new or existing cyclic or continuous catalytic reforming unit shall conduct a performance test for each unit to determine and demonstrate compliance with applicable TOC and HCl emission standards using the test methods and procedures in § 63.1566 of this subpart.

(2) At the first regeneration cycle following the compliance date, the owner or operator of a new or existing semi-regenerative catalytic reforming unit shall conduct an initial performance test for each unit to determine and demonstrate compliance with applicable TOC and HCl emission standards using the test methods and procedures in § 63.1566 of this subpart.

(3) The owner or operator of a new or existing catalytic reforming unit is not required to conduct a performance test to demonstrate compliance with the TOC percent reduction or concentration emission standards in § 63.1562(b)(1)(ii) of this subpart when any of the following control devices are used:

(i) Any boiler or process heater with a design heat input capacity of 44 MW or greater;

(ii) Any boiler or process heater in which all vent streams are introduced into the flame zone; or

(iii) Any flare that complies with the control device requirements in § 63.11(b) of this part.

(d) *Performance tests—sulfur recovery units.* During the first 150 days following the compliance date, the owner or operator of a new or existing sulfur recovery unit shall conduct a performance test for each unit to determine and demonstrate compliance with the applicable emission standard for TRS compounds using the test methods and procedures in § 63.1566 of this subpart.

(e) *Test conditions.* Each performance test shall be conducted according to the requirements of § 63.7(e) of this part except that performance tests shall be conducted at maximum representative operating capacity for the process. The owner or operator shall conduct the test while operating the control device at conditions which result in lowest emission reduction.

(1) Each performance test shall consist of three separate runs. Compliance is demonstrated when the average of three runs is less than or equal to the applicable standard.

(2) Data shall be reduced in accordance with the EPA-approved methods specified in § 63.1566 of this subpart or, if other test methods are used, the data and methods shall be validated in accordance with the protocol in Method 301 of appendix A to this part.

(f) *Process/operating parameter range.* The owner or operator of a new or existing catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit shall establish a minimum and/or maximum operating value or procedure for each parameter to be monitored as required by § 63.1565 of this subpart that ensures compliance with the applicable emission standard. To establish the minimum and/or maximum value, the owner or operator shall use the procedures in paragraphs (f)(1) through (f)(9) of this section, as applicable to the control device, and submit the information required by § 63.1567(a)(6) in the notification of compliance status report.

(1) For a thermal incinerator, the owner or operator shall measure and record the combustion zone temperature over the full period of the performance test, record each hourly or 1-hour block average value, and determine the minimum and average combustion zone temperature.

(2) For a catalytic incinerator, the owner or operator shall measure the upstream and downstream temperatures and temperature difference across the catalyst bed over the full period of the performance test, record each hourly or 1-hour block average value, and determine the minimum and average upstream temperature and temperature difference across the catalyst bed.

(3) For a boiler or process heater with a design heat capacity less than 44 MW where the vent stream is not introduced into the flame zone, the owner or operator shall measure the combustion zone temperature over the full period of the performance test, record each hourly or 1-hour block average value, and determine the minimum and average combustion zone temperature.

(4) For a flare, the owner or operator shall record the presence of a flame at the pilot light over the full period of the compliance determination.

(5) For an electrostatic precipitator, the owner or operator shall measure the voltage and secondary current or the total power input over the full period of the performance test, record each hourly or 1-hour block average value, and determine the minimum and average hourly voltage and secondary current or total power input.

(6) For a wet scrubber, the owner or operator shall measure the pressure drop across the scrubber, the gas flow rate, and the total water (or scrubbing liquid) flow rate to the scrubber over the full period of the performance test, record each hourly or 1-hour block average value, and determine the minimum and average pressure drop, the maximum and average gas flow rate, the minimum and average total water (or scrubbing liquid) flow rate, and the minimum and average liquid-to-gas ratio.

(7) For a catalytic cracking unit that does not use a combustion device where

the owner or operator elects to monitor operating parameters under § 63.1565(d)(2) of this subpart, the owner or operator shall measure the temperature of the catalytic cracking unit and the oxygen content of the regenerator exhaust gas over the full period of the performance test, record each hourly or 1-hour block average value, and determine the minimum and average hourly temperature and oxygen content.

(8) The owner or operator of a catalytic cracking unit catalyst regenerator subject to the PM emission standard in § 63.1562(a)(1)(i) of this subpart shall determine and record the average coke burn-off rate (thousands of kg/hr) and the hours of operation for the unit.

(9) For all control devices, the owner or operator shall record whether the flow indicator, if required, was operating and whether flow was detected at any time during each hour of the full period of the performance test.

§ 63.1565 Monitoring requirements.

(a) *Combustion control device.* Except as provided in paragraph (a)(4) of this section, the owner or operator of a new or existing catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit that uses a combustion control device to comply with the emission standards of this subpart shall install, operate, and maintain the monitoring equipment specified in paragraph (a)(1), (a)(2), or (a)(3) of this section, depending on the type of combustion control device used.

(1) Where an incinerator is used:

(i) For each thermal incinerator, a measurement device equipped with a continuous recorder to measure and record the daily average combustion zone temperature. The measurement device shall be installed in the combustion zone or in the ductwork immediately downstream of the combustion zone in a position before any substantial heat exchange occurs; or

(ii) For each catalytic incinerator, a measurement device equipped with a continuous recorder to measure and record the daily average upstream temperature and temperature difference across the catalyst bed. The measurement devices shall be installed in the gas stream immediately before and after the catalyst bed.

(iii) The accuracy of the temperature measurement device shall be ±1 percent of the temperature being measured, expressed in degrees Celsius (C) or ±0.5°C, whichever is greater.

(iv) The owner or operator shall verify the calibration of the temperature measurement device every 3 months.

(2) Where a flare is used, a device (including but not limited to a thermocouple, an ultraviolet beam sensor, or an infrared sensor) that continuously detects the presence of a pilot flame. The owner or operator shall record, for each 1-hour period, whether the monitor was continuously operating and whether a pilot flame was continuously present during each hour.

(3) Where a boiler or process heater with a design heat capacity less than 44 MW where the vent stream is not introduced into the flame zone is used, a measurement device equipped with a continuous recorder to measure and record the daily average combustion zone temperature.

(i) The accuracy of the temperature measurement device shall be ±1 percent of the temperature being measured, expressed in degrees C or ±0.5°C, whichever is greater.

(ii) The owner or operator shall verify the calibration of the temperature measurement device every 3 months.

(4) Any boiler or process heater with a design heat capacity greater than or equal to 44 MW or any boiler or process heater in which all vent streams are introduced into the flame zone is exempt from the monitoring requirements in this paragraph.

(b) *Catalytic cracking unit—electrostatic precipitator.* The owner or operator of a new or existing catalytic cracking unit that uses an electrostatic precipitator to comply with the emission standards of this subpart shall install, operate, and maintain a measurement device equipped with a continuous recorder to measure and record the average hourly voltage and secondary current or the average hourly total power input.

(c) *Catalytic cracking unit/catalytic reforming unit—scrubber.* The owner or operator of a new or existing catalytic cracking unit or catalytic reforming unit that uses a wet scrubber to comply with the emission standards of this subpart shall install, calibrate, operate, and maintain:

(1) A measurement device equipped with a continous recorder to measure and record the average daily pressure drop across the scrubber, the average daily gas flow rate to the scrubber, and the average daily total water (or scrubbing liquid) flow rate to the scrubber.

(i) The pressure drop monitor is to be certified by the manufacturer to be accurate within ±250 pascals (±1 inch water gauge) over its operating range. The flow rate monitors are to be certified by their manufacturers to be accurate within ±5 percent over their operating ranges.

(ii) The owner or operator shall verify the calibration of the pressure drop and flow rate monitors every 3 months.

(2) The owner or operator shall calculate and record the daily average liquid-to-gas ratio.

(d) *Catalytic cracking unit—no combustion device.* Each owner or operator of a new or existing catalytic cracking unit regenerator that does not use a combustion device to comply with the CO emission standard in § 63.1562(a)(2) of this subpart shall install, calibrate, operate, and maintain a continuous emission monitoring system as described in paragraph (d)(1) of this section or a continous parameter monitoring system as described in paragraph (d)(2) of this section.

(1) The owner or operator shall install, operate, calibrate, and maintain a continuous emission monitoring system to measure and record the concentration of CO in the exhaust gases of each catalytic cracking unit regenerator vent and determine the hourly average concentration in ppm by volume (dry basis) of CO emissions into the atmosphere.

(i) The continuous emission monitoring system shall meet the requirements of Performance Specification 4A in part 60 of this chapter. The span value for this system is 1,000 ppm CO.

(ii) Each continuous emission monitoring system shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(iii) The owner or operator shall operate and maintain each continuous emission monitoring system in accordance with the requirements of § 63.8 of this part and the quality assurance procedures in appendix F to part 60 of this chapter.

(2) The owner or operator shall install, calibrate, operate, and maintain:

(i) A measurement device equipped with a continuous recorder to measure and record the average hourly temperature of the catalytic cracking unit regeneration unit exhaust gas; and

(ii) A measurement device equipped with a continuous recorder to measure and record the average hourly oxygen content of the regenerator exhaust gas.

(iii) The accuracy of the temperature measurement device shall be ±1 percent of the temperature being measured, expressed in degrees C or ±0.5°C, whichever is greater. The accuracy of the oxygen sensor shall be ±1 percent over its operating range.

(iv) The owner or operator shall verify the calibration of the temperature and oxygen measurement devices every 3 months.

(3) The monitoring requirements in paragraphs (d)(1) and (d)(2) of this section do not apply if the owner or operator demonstrates that the average CO emissions are less than 50 ppm by volume (dry basis) and also files a written request for exemption with the applicable permitting authority and receives such an exemption. The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that meets the requirements of Performance Specification 4A of appendix B to part 60 of this chapter. 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 in appendix A to part 60 of this chapter and employ the sample conditioning system of Method 10A in appendix A to part 60 of this chapter, the alternative relative accuracy test procedure in section 10.1 of Performance Specification 2 of appendix B to part 60 of this chapter may be used in place of the relative accuracy test.

(e) *Catalytic cracking unit catalyst regenerator.* The owner or operator of a catalytic cracking unit catalyst regenerator subject to the PM emission standard in § 63.1562(a)(1)(i) of this subpart shall calculate the daily average coke burn-off rate (thousands of kg/hr) using the calculation procedure in § 63.1566(a)(3) of this subpart (Test methods and procedures) and record the information specified in § 63.1567(e)(4)(xii) of this subpart (Notification, reporting, and recordkeeping requirements). For purposes of daily average coke burn-off calculations, the exhaust gas flow can be calculated from process data.

(f) *Catalytic cracking unit—no electrostatic precipitator or scrubber.* An owner or operator of a new or existing catalytic cracking unit that does not use an electrostatic precipitator or scrubber to comply with the PM or Ni emission standards in § 63.1562(a)(1) of this subpart shall include, subject to approval of the applicable permitting authority, a recommended continuous parameter monitoring system for each affected source in the part 70 or part 71 permit application. Each application shall include the information required in § 63.1567(a)(6)(v)(B) of this subpart (Notification, reporting, and recordkeeping requirements).

(g) *Sulfur recovery unit—no combustion device.* The owner or operator of a new or existing sulfur recovery unit that does not use a combustion device to comply with the TRS emission standard in § 63.1562(c) of this subpart shall include, subject to approval by the applicable permitting authority, a recommended continuous parameter monitoring system for each affected source in the part 70 or part 71 permit application. Each application shall include the information required in § 63.1567(a)(6)(v)(B) of this subpart (Notification, reporting, and recordkeeping requirements).

(h) *Bypass line.* The owner or operator of a new or existing catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit using a vent system that contains a bypass line that could divert a vent stream away from the control device used to comply with the emission limits in this subpart shall comply with the requirements of either paragraph (h)(1) or (h)(2) of this section. Equipment such as low leg drains, high point bleed, analyzer vents, open-ended valves or lines, or pressure relief valves needed for safety reasons are not subject to the requirements of this paragraph.

(1) Install, calibrate, operate, and maintain a flow indicator. The device shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere. The owner or operator shall visually inspect the flow indicator at least once every hour to determine that the flow indicator is operating properly and whether gas or vapor are present in the bypass line and record the information specified in § 63.1567(e)(4)(x) of this subpart (Notification, reporting, and recordkeeping requirements); or

(2) Secure the bypass line valve in the closed position with a car-seal or a lock-and-key type configuration. The device shall be placed on the mechanism by which the bypass device position is controlled (e.g., valve handle, damper level) when the bypass device is in the closed position such that the bypass line valve cannot be opened without breaking the seal or removing the device. The owner or operator shall visually inspect the seal or closure mechanism at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line, and record the information specified in § 63.1567(e)(4)(x) of this subpart (Notification, reporting, and recordkeeping requirements).

(i) *Installation, calibration, operation, and maintenance of monitoring systems and devices.* All continuous parameter monitoring systems and devices required or allowed by this section shall be installed, calibrated, maintained, and operated according to manufacturer's specifications or according to other written procedures that provide adequate assurance that the equipment will monitor accurately.

(j) *Averaging times for continuous parameter monitoring systems.* Each continuous parameter monitoring system shall measure data values at least once every hour and record either:

(1) Each measured data value; or

(2) Block average values for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(3) Daily averages shall be calculated as the average of all values for a monitored parameter recorded during the operating day. The average shall cover a 24-hour period if operation is continuous or the number of hours of operation per day if operation is not continuous.

(4) Monitoring data recorded during periods of unavoidable monitoring system breakdowns, repairs, calibration checks, and zero (low-level) and high-level adjustments; startup, shutdowns, and malfunctions; and periods of nonoperation of the process unit resulting in cessation of the emissions to which the monitoring applies shall not be included in any average computed under this subpart.

(k) *Operation of control device.* The owner or operator of a new or existing affected source equipped with a control device subject to the monitoring provisions of this section shall operate the control device above or below, as appropriate, the minimum or maximum value specified in the notification of compliance status report.

(l) *Parameter changes.* (1) The owner or operator may change the established level of control device or process operating parameters by conducting additional performance tests to verify that, at the new control device or process parameter level, the owner or operator is in compliance with the applicable emission standard in §§ 63.1562 or 63.1563 of this subpart.

(2) The owner or operator shall conduct a new performance test to establish a revised minimum or maximum value for the monitored process or operating parmeter to determine and demonstrate compliance under the new operating conditions if any change to the process or operating

conditions (including but not limited to feedstock, capacity, control device or capture system) that could result in a change in the control system performance or designated conditions has been made since the last performance or compliance tests were conducted.

(m) *Alternative parameters.* (1) The owner or operator of a catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit may request approval to monitor parameters other than those listed in paragraphs (a) through (d) of this section. The request shall be submitted according to the procedures specified in paragraph (m)(2) of this section. Approval shall be requested if the owner or operator:

(i) Uses a control device other than an incinerator, boiler, process heater, flare, electrostatic precipitator, or scrubber;

(ii) Uses one of the control devices listed in paragraphs (a) through (c) of this section, but seeks to monitor a parameter other than those specified in paragraphs (a) through (d) of this section; or

(iii) Uses no control device or a control method, such as pretreatment, rather than an add-on control device.

(2) To apply for use of alternative monitoring parameters, the owner or operator shall submit a request for review and approval or disapproval by the applicable permitting authority. The submittal shall include:

(i) A description of each affected source and the parameter(s) to be monitored to determine whether periods of excess emissions occur, as defined in paragraph (o) of this section, and an explanation of the criteria used to select the parameter(s);

(ii) A description of the methods and procedures that will be used to demonstrate that the parameter can be used to determine excess emissions and the schedule for this demonstration. The owner or operator must certify that he/she will establish a minimum and/or maximum value, as applicable, for the monitored parameter(s) that represents the conditions in existence when the control device is being properly operated and maintained; and

(iii) The frequency and content of monitoring, recording, and reporting, if monitoring and recording are not continuous. The rationale for the proposed monitoring, recording, and reporting system shall be included.

(n) *Automated data compression system.* The owner or operator may request approval to use an automated data compression system that does not record monitored operating parameter values at a set frequency (e.g., once every hour) but records all values that meet set criteria for variation from previously recorded values.

(1) The requested system shall be designed to:

(i) Measure the operating parameter value at least once every hour;

(ii) Record at least 24 values each day during periods of operation;

(iii) Record the date and time when monitors are turned off or on;

(iv) Recognize unchanging data that may indicate the monitor is not functioning properly, alert the operator, and record the incident; and

(v) Compute daily average values of the monitored operating parameter based on recorded data.

(2) The request shall contain a description of the monitoring system and data recording system including the criteria used to determine which monitored values are recorded and retained, the method for calculating daily averages, and a demonstration that the system meets all criteria of paragraph (j)(1) of this section.

(o) *Excess emissions.* (1) Period of excess emissions means any of the following conditions:

(i) For a thermal incinerator, an operating day when the daily average temperature falls below the minimum value specified in the notification of compliance status report;

(ii) For a catalytic incinerator, an operating day when the daily average upstream temperature or the daily average temperature difference across the catalyst bed falls below the minimum value specified in the notification of compliance status report;

(iii) For a boiler or process heater with a design heat capacity less than 44 MW where the vent stream is not introduced into a flame zone, an operating day when the daily average temperature falls below the minimum value specified in the notification of compliance status report;

(iv) For an electrostatic precipitator, any period when the average hourly voltage or secondary current or the average hourly total power input falls below the minimum value specified in the notification of compliance status report;

(v) For a wet scrubber, an operating day when the daily average pressure drop or daily average liquid-to-gas ratio falls below the minimum value specified in the notification of compliance status report;

(vi) For a catalytic cracking unit with no combustion device, any period when the average hourly CO concentration measured by the CO continuous emission monitoring system required by paragraph (d)(1) of this section exceeds 500 ppmv or any period when the average hourly temperature or oxygen content falls below the minimum value specified in the notification of compliance status report;

(vii) For a catalytic cracking unit catalyst regenerator subject to the PM emission standard in § 63.1562(a)(1)(i) of this subpart, an operating day when the daily average coke burn-off rate exceeds the value specified in the notification of compliance status report;

(viii) An operating day when all pilot flames of a flare are absent;

(ix) An operating day when monitoring data are available for less than 75 percent of the operating hours;

(x) For data compression systems approved under paragraph (n) of this section, an operating day when the monitor operated for less than 75 percent of the operating hours or a day when less than 18 monitoring values were recorded; or

(xi) A period when flow to the control device is diverted or otherwise by-passed.

(2) Multiple excursions from the same control device during the applicable averaging period (e.g. 1-hour, 24-hours) constitutes a single excursion.

(p) *Violation.* Monitoring data under this subpart are directly enforceable to determine compliance with the required operating conditions for the monitored control devices. For each period of excess emissions, as defined in paragraph (o) of this section, the owner or operator shall be deemed to have failed to have applied the control in a manner that achieves the required operating conditions. More than one exceedance or excursion by the same control device during a semi-annual reporting period is a violation of this subpart.

§ 63.1566 Test methods and procedures.

(a) The owner or operator of a catalytic cracking unit shall determine compliance with the PM emission standard in § 63.1562(a)(1)(i) of this subpart as follows:

(1) The emission rate (E) of PM shall be computed for each run using Equation 1:

$$E = \frac{K \times C_s \times Q_{sd}}{R_c} \qquad \text{(Eq. 1)}$$

where,

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

C_s = Concentration of PM, g/dscm (lb/dscf);

Q_{sd} = Volumetric flow rate of effluent gas, dscm/hr (dscf/hr);

R_c = Coke burn-off rate, kg coke/hr (1,000 lb coke/hr); and

K = Conversion factor, 1.0 (kg^2/g)/(1,000 kg) [1,000 lb/(1,000 lb)].

(2) Method 5B or 5F in appendix A to part 60 of this chapter is to be used to determine PM emissions and associated moisture content from affected facilities without wet flue gas desulfurization (FGD) systems; only Method 5B in appendix A to part 60 of this chapter is to be used after wet FGD systems. The sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the permitting authority when process variables or other factors preclude sampling for at least 60 minutes.

(3) The coke burn-off rate (R_c) shall be computed for each run using Equation 2:

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

Where,

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

Q_r = Volumetric flow rate of exhaust gas from catalyst regenerator before additional air or gas streams are added (e.g., measurements may be made after an ESP, but must be made before a CO boiler), dscm/min (dscf/min);

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

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

$\%CO$ = Carbon monoxide concentration in regenerator exhaust, percent by volume (dry basis);

$\%O_2$ = Oxygen concentration in regenerator exhaust, percent by volume (dry basis);

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

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

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [(0.0062 (lb-min)/(hr-dscf-%)];

Q_{oxy} = Volumetric flow rate of oxygen-enriched air stream to regenerator, as determined from the catalytic cracking unit control room instrumentation, dscm/min (dscf/min); and

$\%O_{xy}$ = Oxygen concentration in oxygen-enriched air stream, percent by volume (dry basis).

(i) Method 2 in appendix A to part 60 of this chapter shall be used to determine the volumetric flow rate (Q_r) for a performance test; for daily calculations, the volumetric flow rate can be determined using process data.

(ii) The emission correction factor, integrated sampling and analysis procedure of Method 3 in appendix A to part 60 of this chapter shall used to determine CO_2, CO, and O_2 concentrations.

(b) The owner or operator shall determine compliance with the Ni standard in § 63.1562(a)(1)(ii) of this subpart using the procedures in paragraphs (b)(1) through (b)(3) of this section.

(1) Method 29 in appendix A to part 60 of this chapter shall be used to determine the concentration of Ni in the catalytic cracking unit catalyst regenerator flue gas. The sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.014 dscm/min (0.5 dscf/min).

(2) Method 2 in appendix A to part 60 of this chapter shall be used to determine volumetric flow rate (Q_{sd}).

(3) The mass emission rate (E_{Ni}) shall be computed for each run using Equation 3:

$$E_{Ni} = C_{Ni} \times Q_{sd} \qquad \text{(Eq. 3)}$$

Where,

E_{Ni} = Mass emission rate of Ni, mg/hr (lb/hr);

C_{Ni} = Ni concentration in the catalytic cracking unit catalyst regenerator flue gas as measured by Method 29 in appendix A to part 60 of this chapter, mg/dscm (lbs/dscf); and

Q_{sd} = Volumetric flow rate of the catalytic cracking unit catalyst regenerator flue gas as measured by Method 2 in appendix A to part 60 of this chapter, dscm/hr (dscf/hr).

(c) The owner or operator shall determine compliance with the CO emission standard in § 63.1562(a)(2) of this subpart by using the integrated sampling technique of Method 10 in appendix A to part 60 of this chapter to determine the CO concentration (dry basis). The sampling time for each run shall be 60 minutes.

(d) The owner or operator of a catalytic reforming unit using a flare to comply with the TOC emission standard in § 63.1562(b)(1) of this subpart shall determine compliance with the visible emission standard as required by § 63.11(b)(4) of this part using Method 22 in appendix A to part 60 of this chapter.

(e) Except as provided in the performance test provisions for catalytic reforming units in § 63.1564(c)(3) of this subpart and in paragraph (i) of this section, the owner or operator shall determine compliance with the 98 percent reduction standard for TOC in § 63.1562(b)(1)(ii) of this subpart by measuring emissions at the inlet and at the outlet of the control device to determine percent reduction using the following test methods and procedures:

(1) Methods 1 or 1A in appendix A to part 60 of this chapter shall be used for selection of the sampling site.

(2) No traverse site selection method is needed for vents smaller than 0.10 meter in diameter.

(3) The gas volumetric flow rate shall be determined using Methods 2, 2A, 2C, or 2D in appendix A to part 60 of this chapter, as appropriate.

(4) Method 18 or Method 25A in appendix A to part 60 of this chapter shall be used to measure TOC concentration. Alternatively, any other method or data that has been validated according to the protocol in Method 301 of appendix A of this part may be used. The following procedures shall be used to calculate ppm by volume concentration:

(i) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run;

(ii) The TOC concentration (C_{TOC}) is the sum of the concentrations of the individual components and shall be computed for each run using Equation 4 if Method 18 is used:

$$C_{TOC} = \frac{\sum_{i=1}^{x} \left(\sum_{j=1}^{n} C_{ji} \right)}{X} \qquad \text{(Eq. 4)}$$

Where,

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, parts per million by volume;

C_{ji} = Concentration of sample component j of the sample i, dry basis, parts per million by volume;

n = Number of components in the sample; and

x = Number of samples in the sample run.

(5) The emission rate of TOC minus methane and ethane (E_{TOC}) shall be calculated using Equation 5 if Method 18 in appendix A to part 60 of this chapter is used:

$$E = K_2 \left[\sum_{j=1}^{n} C_j M_j \right] Q_s \qquad \text{(Eq. 5)}$$

Where,

E = Emission rate of TOC (minus methane and ethane) in the sample, kilograms per hour;

K_2 = Constant, 2.494×10^{-6} (parts per million)$^{-1}$ (gram-mole per standard cubic meter) (kilogram per gram) (minutes per hour), where the standard temperature (standard cubic meter) is at 20°C;

C_j = Concentration on a dry basis of organic compound j in ppm as measured by Method 18 in appendix A to part 60 of this chapter. C_j includes all organic compounds measured minus methane and ethane;

M_j = Molecular weight of organic compound j, gram per gram-mole; and

Q_s = Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 °C.

(6) If Method 25A in appendix A to part 60 of this chapter is used the emission rate of TOC (E_{TOC}) shall be calculated using Equation 6:

$$E = K_3 \, C_{TOC} \, Q_s \qquad \text{(Eq. 6)}$$

Where,

E = Emission rate of TOC (minus methane and ethane) in the sample, kilograms per hour;

K_3 = Constant, 2.64×10^{-3} (parts per million)$^{-1}$ (gram-mole per standard cubic meter) (gram per gram-mole) (kilogram per gram) (minutes per hour), where the standard temperature (standard cubic meter) is at 20°C;

C_{TOC} = Concentration of TOC on a dry basis in ppm by volume as propane as measured by Method 25A in appendix A to part 60 of this chapter, as indicated in paragraph (f)(4) of this section; and

Q_s = Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 °C.

(f) Except as provided in the performance test provisions for a catalytic reforming unit in § 63.1564(c)(3) of this subpart and paragraph (i) of this section, the owner or operator shall determine compliance with the requirements for a TOC limit of 20 ppm in § 63.1562(b)(1)(ii) of this subpart by sampling at the outlet of the control device using Methods 18 or 25A in appendix A to part 60 of this chapter and the procedures in paragraph (e)(4) of this section to determine concentration.

(g) The owner or operator shall determine compliance with the TRS standards in §§ 63.1562(c) and 63.1563(c) of this subpart as follows:

(1) Method 15 of appendix A to part 60 of this chapter shall be used to determine the concentration of TRS. Each run shall consist of 16 samples taken over a minimum 3 hours. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5 square meters (m^2) or 54 square feet (ft^2) or at a point no closer to the walls than 1 meter (m) or 39 inches (in) if the cross-sectional area is 5 m^2 or more and the centroid is more than 1 m from the wall. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3 liters per minute (lpm) or 0.10 cubic feet per minute (cfm). The SO_2 equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO2 equivalent for each sample during the run.

(2) Method 4 of appendix A to part 60 of this chapter shall be used to determine the moisture content of the gases. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

(3) The oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 in appendix A to part 60 of this chapter. The samples shall be taken simultaneously with reduced sulfur or moisture samples. The reduced sulfur samples shall be corrected to zero percent excess air using Equation 7:

$$C_{adj} = C_{meas} \left[20.9_c / (20.9 - \%O_2) \right] \qquad \text{(Eq. 7)}$$

Where,

C_{adj} = pollutant concentration adjusted to zero percent oxygen, ppm or g/dscm;

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

20.9_c = 20.9 percent oxygen—0.0 percent oxygen (defined oxygen correction basis), percent;

20.9 = oxygen concentration in air, percent; and

$\%O_2$ = oxygen concentration measured on a dry basis, percent.

(h) The owner or operator shall determine compliance with the HCl emission standards in §§ 63.1562(b)(2) and (b)(3) and § 63.1563(b)(2) of this subpart using Method 26A in appendix A to part 60 of this chapter. To determine percent reduction, sampling shall be performed at the inlet and at the outlet of the control device. The sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.021 dscm/min (0.74 dscf/min).

(i) Engineering assessment may be used to determine the emission reduction or outlet concentration for the representative operating condition expected to yield the highest daily emission rate. Engineering assessment includes, but is not limited to, the following:

(1) Previous test results provided the tests are representative of current operating practices at the process unit;

(2) Bench-scale or pilot-scale test data representative of the process under representative operating conditions;

(3) TOC emission rate specified or implied within a permit limit applicable to the process vent;

(4) Design analysis based on accepted chemical engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

(i) Use of material balances based on process stoichiometry to estimate maximum TOC concentrations;

(ii) Estimation of maximum flow rate based on physical equipment design such as pump or blower capacities; and

(iii) Estimation of TOC concentrations based on saturation conditions.

(5) Engineering assessments based on approaches other than those listed above shall be subject to review and approval by the applicable permitting authority.

(6) All data, assumptions, and procedures used in the engineering assessment shall be documented to the satisfaction of the applicable permitting authority.

(j) The owner or operator may use an alternative test method subject to approval by the Administrator.

§ 63.1567 Notification, reporting, and recordkeeping requirements.

(a) *Notifications.* The owner or operator shall submit written initial notifications to the applicable permitting authority as described in paragraphs (a)(1) through (a)(7) of this paragraph:

(1) As required by § 63.9(b)(1) of this part, the owner or operator shall provide notification for an area source that subsequently increases its emissions such that the source is a major source subject to the standard.

(2) As required by § 63.9(b)(3) of this part, the owner or operator of a new or reconstructed affected source, or a source that has been reconstructed such that it is an affected source, that has an initial startup after the effective date of this subpart and for which an application for approval or construction or reconstruction is not required under § 63.5(d) of this part, shall provide notification that the source is subject to the standard. The notification shall contain the general information required for the notification of compliance status in paragraph (a)(6)(i) of this section.

(3) As required by § 63.9(b)(4) of this part, the owner or operator of a new or reconstructed major affected source that has an initial startup after the effective date of this subpart and for which an application for approval of construction or reconstruction is required by § 63.5(d) of this part shall provide the following notifications:

(i) Notification of intention to construct a new major affected source, reconstruct a major source, or reconstruct a major source such that the source becomes a major affected source;

(ii) Notification of the date when construction or reconstruction was commenced (submitted simultaneously with the application for approval of construction or reconstruction if construction or reconstruction was commenced before the effective date of this subpart or no later than 30 days of the date construction or reconstruction commenced if construction or reconstruction commenced after the effective date of this subpart);

(iii) Notification of the anticipated date of startup; and

(iv) Notification of the actual date of startup.

(4) As required by § 63.9(b)(5) of this part, after the effective date of this subpart, an owner or operator who intends to construct a new affected source or reconstruct an affected source subject to this subpart, or reconstruct a source such that it becomes an affected source subject to this subpart shall provide notification of the intended construction or reconstruction. The notification shall include all the information required for an application for approval of construction or reconstruction as required by § 63.5(d) of this part. For major sources, the application for approval of construction or reconstruction may be used to fulfill these requirements.

(i) The application shall be submitted as soon as practicable before the construction or reconstruction is planned to commence (but no sooner than the effective date) if the construction or reconstruction commences after the effective date of this subpart; or

(ii) The application shall be submitted as soon as practicable before startup but no later than 90 days after the effective date of this subpart if the construction or reconstruction had commenced and initial startup had not occurred before the effective date.

(5) As required by §§ 63.9(e) and 63.9(f) of this part, the owner or operator shall provide notification of the anticipated date for conducting performance tests and visible emission observations for flares. The owner or operator shall notify the Administrator of the intent to conduct a performance test or perform visible emission observations to determine compliance with flare requirements at least 30 days before the test is scheduled.

(6) Each owner or operator of a source subject to this subpart shall submit a notification of compliance status report within 150 days after the compliance dates specified in § 63.1564(a) of this subpart. The notification shall be signed by the responsible official who shall certify its accuracy. A complete notification compliance status report shall include the information in paragraphs (a)(6)(i) through (a)(6)(vii) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination. In a State with an approved operating permit program where delegation of authority under section 112(l) of the Act has not been requested or approved, the owner or operator shall provide a duplicate notification to the applicable Regional Administrator. If the required information has been submitted before the date 150 days after the compliance date specified in § 63.1564(a) of this subpart, a separate notification of compliance status report is not required. If an owner or operator submits the information specified in paragraphs (a)(6)(i) through (a)(6)(vii) of this section at different times or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information.

(i) General information:

(A) The name and address of the owner or operator;

(B) The address (i.e., physical location) of the affected source;

(C) An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date; and

(D) A statement of whether the source is a major source or an area source. If the facility is an area source, the remaining informational requirements in this paragraph are not applicable.

(ii) A brief description of each affected source, including:

(A) The nature, size, design, and method of operation;

(B) Operating design capacity; and

(C) Identification of each point of emission for each HAP, or if a definitive identification is not yet possible, a preliminary identification of each point of emission for each HAP.

(iii) A brief description of each affected source not subject to the monitoring requirements of this subpart, including:

(A) Identification of any boiler or process heater with a design heat input capacity greater than or equal to 44 MW or any boiler or process heater in which all vent streams are introduced into the flame zone for which monitoring is not required;

(B) Identification of any catalytic cracking unit regenerator that does not use a combustion device to comply with CO emission standard in § 63.1562(a)(2) of this subpart for which monitoring is not required, including CO emission monitoring data and quality assurance test results as described in § 63.1564(b)(2) of this subpart, a copy of the exemption approved by the applicable permitting authority, and information and data demonstrating that the average CO emissions are less than 50 ppm by volume as required by § 63.1565(d)(3) of this subpart; and

(C) Identification of each catalytic reforming unit for which control device requirements do not apply due to depressuring and purging operations at a differential pressure between the reactor vent and the gas transfer system to the control device of less than 1 psig or when the reactor vent pressure is 1 psig or less.

(iv) A description of the air pollution control equipment or method of compliance for each affected source, including the PM or Ni emission standard selected under § 63.1562(a) and the catalytic cracking unit and sulfur recovery unit emission standards and requirements selected under § 63.1560(d) of this subpart (Applicability and designation of sources).

(v) The methods used to determine compliance for each affected source, including:

(A) The engineering assessment specified in § 63.1566(i) of this subpart or the results of the performance test specified in § 63.1564 of this subpart. Performance test results shall include operating ranges of key process and control parameters during the performance test; the value, averaged over the period of the performance test, of each parameter identified in the operating permit as being monitored in accordance with § 63.1565 of this subpart; and applicable supporting calculations;

(B) The minimum and/or maximum parameter value, as applicable for each monitored parameter for each emission point and the data and rationale used to develop the range, including any data and calculations used to develop the value and a description of why the value indicates proper operation of the control device. For any recommended continuous parameter monitoring system for a catalytic cracking unit that does not use an electrostatic precipitator or scrubber to comply with the PM or Ni emission standard in § 63.1562(a)(1) of this subpart or a sulfur recovery unit that does not use a combustion device to comply with the TRS emission standard in § 63.1562(c) of this subpart, the owner or operator shall provide data and rationale for the recommended system. Following approval of the recommended system by the permitting authority, the owner or operator shall provide the information described in this paragraph for each monitored parameter;

(C) The definition of ''operating day'' for each incinerator, flare, boiler or process heater with a design input capacity less than 44 MW where the vent stream is not introduced into the flame zone, and catalytic cracking unit or catalytic reforming unit using a scrubber for the purpose of determining daily average values of monitored parameters. The definition, subject to approval by the applicable permitting authority, shall specify the times at which an operating day begins and ends; it may be from midnight to midnight or another daily period; and

(D) If a flare is used to comply with the TOC standards in § 63.1562(b)(1) of this subpart, the flare design (e.g., steam-assisted, air-assisted, or non-assisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination and all periods when the pilot flame is absent.

(vi) Operation, maintenance, and monitoring information, including:

(A) A description of the method that will be used for determining continuing compliance for each affected source, including a description of the monitoring and reporting requirements and test methods;

(B) A monitoring schedule, including identification of those time periods when control device or process parameter monitoring would be conducted and when monitoring would not be conducted (e.g., monitoring of emissions from catalytic reforming unit regeneration vents is required only when the regeneration process is performed);

(C) A maintenance schedule for each process and control device consistent with the manufacturer's instructions and recommendations for routine and long-term maintenance; and

(D) Quality control program for continuous parameter monitoring systems and continuous emission monitoring systems, including procedures (as applicable) for initial and subsequent calibrations, preventative maintenance, accuracy audit procedures; corrective action; and data recording, calculation, reporting, and recordkeeping procedures to document conformance.

(vii) A statement by the owner or operator as to whether the existing, new, or reconstructed source is in compliance with the requirements of this subpart.

(b) *Reports—periodic.* The owner or operator of a source subject to this subpart shall submit semi-annual reports no later than 60 calendar days after the end of each 6-month period if any period of excess emissions, as defined in § 63.1565(o) of this subpart, occurs during the reporting period. The first 6-month period shall begin on the date the notification of compliance status report is required to be submitted. An owner or operator may submit reports required by other regulations in place of or as part of the periodic report required by this paragraph if the reports contain the information required by paragraphs (b)(1) through (b)(7) of this section. A periodic report is not required if none of the exceptions specified in paragraphs (b)(1) through (b)(5) of this section occur during a 6-month period:

(1) Monitoring results for an operating day when:

(i) For a thermal incinerator, the daily average temperature falls below the minimum value specified in the notification of compliance status report;

(ii) For a catalytic incinerator, the daily average upstream temperature or the daily average temperature difference across the catalyst bed falls below the minimum value specified in the notification of compliance status report;

(iii) For a boiler or process heater with a design heat capacity less than 44 MW where the vent stream is not introduced into a flame zone, the daily average temperature falls below the minimum value specified in the notification of compliance status report;

(iv) For an electrostatic precipitator, the average hourly voltage or secondary current or average hourly total power input falls below the minimum value specified in the notification of compliance status report;

(v) For a wet scrubber, the daily average pressure drop or daily average liquid-to-gas ratio falls below the minimum value specified in the notification of compliance status report;

(vi) For a catalytic cracking unit with no combustion device, the average hourly CO concentration measured by the CO continuous emission monitoring system required by § 63.1565(d)(1) of this subpart exceeds 500 ppmv or any period when the average hourly temperature or oxygen content falls below the minimum value specified in the notification of compliance status report; or

(vii) For a catalytic cracking unit catalyst regenerator subject to the PM emission standard in § 63.1562(a)(1)(i) of this subpart, the daily average coke burn-off rate (thousands kg/hr) exceeds the maximum value specified in the notification of compliance status report.

(2) The duration of a period during an operating day when monitoring data were not available for 75 percent of the operating hours;

(3) The duration of a period during an operating day when all pilot flames of a flare are absent;

(4) The time and duration of any period a vent stream is diverted through a bypass line; or

(5) For data compression systems approved under § 63.1565(n) of this subpart, an operating day when the monitor operated for less than 75 percent of the operating hours or a day when less than 18 monitoring values were recorded.

(6) The owner or operator shall submit the results of any performance test conducted during the reporting period including one complete report for each test method used for a particular kind of emission point tested. For additional tests performed for a similar emission point using the same method, results and any other information required shall be submitted, but a complete test report is not required. A complete test report shall contain a brief process description, sampling site data, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of

calculations, and any other information required by the test method.

(7) A request for changing applicability of the PM or Ni emission standard in § 63.1562(a) of this subpart or for changing the applicability of emission standards in this subpart to/from the new source performance standard in subpart J to part 60 of this chapter as allowed under § 63.1560(d) of this subpart (Applicability and designation of affected sources) shall be included in a periodic report. The request must be accompanied by all information and data necessary to demonstrate compliance with the emission standard and associated requirements of this subpart.

(c) *Reports—startup, shutdown, and malfunctions.* The owner or operator shall develop and implement a written plan containing specific procedures to be followed for operating the source and maintaining the source during periods of startup, shutdown, and malfunction and a program of corrective action for malfunctioning process and control systems used to comply with the standard in accordance with the operation and maintenance requirements in § 63.6(e)(3) of this part. The duty to develop and implement the plan shall be incorporated in the facility's part 70 or part 71 operating permit. Each plan shall contain corrective action procedures to be followed if any of the events in paragraphs (b)(1) through (b)(3) of this section occur during the 6-month reporting period, including procedures to determine the cause of the exceedance or deviation, the time the exceedance or deviation began and ended, and for recording the actions taken to correct the cause of the exceedance or deviation. The following reporting and recordkeeping requirements apply to startups, shutdowns, and malfunctions:

(1) When the actions taken to respond are consistent with the plan, keep records to document the event and the response as required in § 63.6(e)(3)(iii) of this part. The owner or operator is not required to report these events in the semi-annual startup, shutdown, and malfunction report required under § 63.10(d)(1) of this part when the actions are consistent with the plan, and the reporting requirements in § 63.6(e)(3)(iii) and § 63.10(d)(5) of this part do not apply.

(2) When the actions taken to respond are not consistent with the plan, keep records to document the event and the response as required in § 63.6(e)(3)(iv) of this part. The owner or operator shall report these events and the response taken in the semi-annual startup, shutdown, and malfunction report required under § 63.10(d)(1) of this part. In this case, the reporting requirements in § 63.6(e)(3)(iv) and § 63.10(d)(5) of this part do not apply.

(3) The owner or operator may include the semi-annual startup, shutdown, and malfunction report required under § 63.10(d)(1) of this part in the periodic report required by paragraph (b) of this section.

(d) *Annual compliance certification.* For the purpose of annual certifications of compliance required by the permitting regulations in parts 70 or 71 of this chapter, the owner or operator shall certify continuing compliance based upon the following conditions:

(1) All periods of excess emissions, including exceedances or excursions, that occurred during the year have been reported as required by this subpart; and

(2) All monitoring, recordkeeping, and reporting requirements were met during the year.

(e) *Recordkeeping.* (1) The owner or operator must retain each record required by this subpart for at least 5 years following the date of each occurrence, measurement, maintenance activity, corrective action, report, or record. The most recent 2 years of records must be retained at the facility. The remaining 3 years of records may be retained off site;

(2) The owner or operator may retain records on microfilm, on a computer, on computer disks, on magnetic tape, or on microfiche;

(3) The owner or operator may report required information on paper or on a labeled computer disc using commonly available and compatible computer software; and

(4) The owner or operator shall maintain records of the following information:

(i) A copy of the startup, shutdown, and malfunction plan;

(ii) Records documenting the actions taken when a startup, shutdown, or malfunction occurred and information to demonstrate that such actions were consistent with the plan;

(iii) All maintenance performed on air pollution control equipment;

(iv) Each period when a continuous monitoring system or continuous emission monitor was inoperative or malfunctioning;

(v) All measurements, test results (including a complete performance test report for each affected source), and any other information needed to demonstrate compliance with the standards in this subpart;

(vi) All documentation supporting notifications of compliance status;

(vii) All documentation supporting conformance with appendix F of part 60 of this chapter for each continuous emission monitoring system, including calibration checks and relative accuracy test audits;

(viii) For owners or operators using continuous monitoring systems or continuous emission monitoring systems to demonstrate compliance, records for such systems as required by § 63.10(c) of this part;

(ix) Records of any changes to a regulated process, including a record of any changes in the location at which the vent stream is introduced into the flame zone for a boiler or process heater;

(x) Where a bypass line is equipped with a flow indicator, records of each hourly inspection demonstrating whether the flow indicator was operating properly and whether gas or vapor flow was detected or where a bypass line is secured with a car-seal or a lock-and-key type device, records of each monthly inspection demonstrating that the bypass line valve is maintained in the closed position and whether gas or vapor flow was detected; and for all bypass line valves, records of the times and durations of all periods when the vent stream is diverted through a bypass line;

(xi) Records of hourly inspections of flare pilot flame; and

(xii) For each catalytic cracking unit catalytic regenerator subject to the PM emission standard in § 63.1562(a)(1)(i) of this subpart, records of the daily average coke burn-off rate, the hours of operation for each unit, and process data used to determine the volumetric flow rate of exhaust gas.

§ 63.1568 Applicability of general provisions.

The requirements of the general provisions in subpart A of this part that are applicable to the owner or operator subject to the requirements of this subpart are shown in appendix A to this subpart.

§ 63.1569 Delegation of authority.

In delegating implementation and enforcement authority to a State under section 112(l) of the Act, all authorities are transferred to the State.

§ 63.1570–63.1579 [Reserved]

Appendix A to Subpart UUU to Part 63—Applicability of General Provisions (40 CFR Part 63, Subpart A) to Subpart UUU

Citation	Applies to subpart UUU	Comment
63.1(a)(1)–63.1(a)(3)	Yes	General Applicability.
63.1(a)(4)	No	This table specifies applicability of General Provisions to Subpart UUU.
63.1(a)(5)	No	[Reserved].
63.1(a)(6)–63.1(a)(8)	No.	
63.1(a)(9)	No	[Reserved].
63.1(a)(10)	No	Subpart UUU specifies calendar or operating day.
63.1(a)(11)–63.1(a)(14)	Yes.	
63.1(b)(1)	No	Initial Applicability Determination Subpart UUU specifies applicability.
63.1(b)(2)	Yes.	
63.1(b)(3)	No.	
63.1(c)(1)	No	Subpart UUU specifies requirements.
63.1(c)(2)	No	Area sources are not subject to subpart UU.
63.1(c)(3)	No	[Reserved].
63.1(c)(4)	Yes.	
63.1(c)(5)	Yes	Except that notification requirements in subpart UUU apply.
63.1(d)	No	[Reserved].
63.1(e)	Yes	Applicability of Permit Program.
63.2	Yes	Definitions § 63.1561 specifies that if the same term is defined in Subparts A and UUU, it shall have the meaning given in Subpart UUU.
63.3	Yes	Units and Abbreviations.
63.4(a)(1)–63.4(a)(4)	Yes	[Reserved].
63.4(a)(5)	Yes.	
63.4(b)–63.4(c)	Yes	Circumvention/Severability.
63.5(a)(1)	Yes	Construction and Reconstruction—Applicability Replace term ''source'' and ''stationary source'' in § 63.5(a)(1) with ''affected source''.
63.5(a)(2)	Yes.	
63.5(b)(1)	Yes	Existing, New, Reconstructed Sources—Requirements.
63.5(b)(2)	No	[Reserved].
63.5(b)(3)	Yes.	
63.5(b)(4)	Yes	Replace the reference to § 63.9 with § 63.9(b)(4) and (b)(5).
63.5(b)(5)–(6)	Yes.	
63.5(c)	No	[Reserved].
63.5(d)(1)(i)	Yes	Application for Approval of Construction or Reconstruction Except Subpart UUU specifies the application is submitted as soon as practicable before startup but no later than 90 days (rather than 60) after the promulgation date where construction or reconstruction had commenced and initial startup had not occurred before promulgation.
63.5(d)(1)(ii)	Yes	Except that emission estimates specified in § 63.5(d)(1)(ii)(H) are not required.
63.5(d)(1)(iii)	No	§ 63.1567(b) specifies submission of notification of compliance status report.
63.5(d)(2)	No.	
63.5(d)(3)	Yes	Except § 63.5(d)(3)(ii) does not apply.
63.5(d)(4)	Yes.	
63.5(e)	Yes	Approval of Construction or Reconstruction.
63.5(f)(1)	Yes	Approval of Construction or Reconstruction Based on State Review.
63.5(f)(2)	Yes	Except that 60 days is changed to 90 days and cross-reference to (b)(2) does not apply.
63.6(a)	Yes	Compliance with Standards and Maintenance—Applicability.
63.6(b)(1)	No	New and Reconstructed Sources—Dates Subpart UUU specifies compliance dates.
63.6(b)(2)	No.	
63.6(b)(3)	Yes.	
63.6(b)(4)	No	May apply to standards under section 112(f).
63.6(b)(5)	No	Subpart UUU specifies notification requirements.
63.6(b)(6)	No	[Reserved].
63.6(b)(7)	No.	
63.6(c)(1)	No	Existing Sources—Dates Subpart UUU specifies compliance dates.
63.6(c)(2)–63.6(c)(3)	No.	
63.6(c)(4)	No	[Reserved].
63.6(c)(5)	Yes.	
63.6(d)	No	[Reserved].
63.6(e)(1)–(2)	Yes	Operation and Maintenance Requirements.
63.6(e)(3)(i)–(ii)	Yes	Startup, Shutdown, and Malfunction Plan.
63.6(e)(3)(iii)	Yes.	
63.6(e)(3)(iv)	Yes	Except that reports of actions not consistent with plan are not required within 2 and 7 days of action but rather must be included in next periodic report.
63.6(e)(3)(v)–(viii)	Yes.	
63.6(f)(1)	Yes	Compliance with Emission Standards.
63.6(f)(2)(i)	Yes.	
63.6(f)(2)(ii)	Yes	Subpart UUU specifies use of monitoring data in determining compliance.
63.6(f)(2)(iii)(A)–63.6(f)(2)(iii)(C)	Yes.	
63.6(f)(2)(iii)(D)	No.	
63.6(f)(2)(iv)–(v)	Yes.	
63.6(f)(3)	Yes.	
63.6(g)	Yes	Alternative Standard.

Citation	Applies to subpart UUU	Comment
63.6(h)	No	Compliance with Opacity/VE Standards Subpart UUU does not include opacity/VE standards.
63.6(i)(1)–63.6(i)(14)	Yes	Extension of Compliance.
63.6(i)(15)	No	[Reserved].
63.6(i)(16)	Yes.	
63.6(j)	Yes	Exemption from Compliance.
63.7(a)(1)	No	Performance Test Requirements—Applicability and Dates Subpart UUU specifies the applicable test and demonstration procedures.
63.7(a)(2)	No	Test results must be submitted in the notification of compliance status report due 150 days after the compliance date.
63.7(a)(3)	Yes.	
63.7(b)	Yes	Notifications Except Subpart UUU specifies notification at least 30 days prior to the scheduled test date rather than 60 days.
63.7(c)	Yes	Quality Assurance/Test Plan § 63.1564(b)(2) requires a Q/A plan for CO continuous emission monitoring systems.
63.7(d)	Yes	Testing Facilities.
63.7(e)(1)	Yes	Conduct of Tests.
63.7(e)(2)–63.7(e)(3)	No	Subpart UUU specifies the applicable methods and procedures.
63.7(e)(4)	Yes.	
63.7(f)	No	Alternative Test Method Subpart UUU specifies the applicable methods and provides alternatives.
63.7(g)	No	Data Analysis, Recordkeeping, Reporting Subpart UUU specifies performance test reports and requires additional records for continuous emission monitoring systems.
63.7(h)(1)	Yes	Waiver of Tests.
63.7(h)(3)–63.7(h)(4)	No.	
63.7(h)(5)	Yes.	
63.8(a)	No	Monitoring Requirements Applicability.
63.8(b)(1)	Yes	Conduct of Monitoring.
63.8(b)(2)	No	Subpart UUU specifies the required monitoring locations.
63.8(b)(3)	Yes.	
63.8(c)(1)(i)	Yes	CMS Operation and Maintenance.
63.8(c)(1)(ii)	No	Addressed by periodic reports in § 63.1567(b) of Subpart UUU.
63.8(c)(1)(iii)	Yes.	
63.8(c)(2)	Yes.	
63.8(c)(3)	Yes	Except that operational status verification includes completion of manufacturer written specifications or installation operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment will monitor accurately.
63.8(c)(4)	No	Monitoring frequency is specified in § 63.1565 of Subpart UUU.
63.8(c)(5)	No.	
63.8(c)(8)–63.8(d)	Yes	Quality Control.
63.8(e)	Yes	CMS Performance Evaluation May be required by Administrator.
63.8(f)(1)	Yes	Alternative Monitoring Method.
63.8(f)(2)	Yes.	
63.8(f)(3)	Yes.	
63.8(f)(4)(i)	No	§ 63.1565(f) specifies procedure.
63.8(f)(4)(ii)	Yes.	
63.8(f)(4)(iii)	No.	
63.8(f)(5)(i)	Yes.	
63.8(f)(5)(ii)	No.	
63.8(f)(5)(iii)	Yes.	
63.8(f)(6)	Yes	Applicable to CO continuous emission monitoring system.
63.8(g)	Yes	Data Reduction Applicable to CO continuous emission monitoring system; Subpart UUU specifies data reduction for CMS.
63.9(a)	Yes	Notification Requirements—Applicability Duplicate notification of compliance status report to RA may be required.
63.9(b)(1)(i)	Yes	Initial Notifications.
63.9(b)(1)(ii)	Yes.	
63.9(b)(1)(iii)	Yes.	
63.9(b)(2)	Yes.	
63.9(b)(3)	Yes.	
63.9(b)(4)	Yes	Except that notification is to be submitted within 150 days as part of the compliance status report.
63.9(b)(5)	Yes	Except that notification is to be submitted within 150 days as part of the compliance status report.
63.9(c)	Yes	Request for Compliance Extension.
63.9(d)	Yes	New Source Notification for Special Compliance Requirements.
63.9(e)	Yes	Except notification is required at least 30 days before test.
63.9(f)	Yes	Notification of VE/Opacity Test.
63.9(g)	No.	
63.9(h)	No	Notification of Compliance Status § 63.1567 specifies the applicable requirements.
63.9(i)	Yes	Adjustment of Deadlines.

Citation	Applies to subpart UUU	Comment
63.9(j)	No	Change in Previous Information.
63.10(a)	Yes	Recordkeeping/Reporting—Applicability.
63.10(b)(1)	No	General Requirements Subpart UUU specifies applicable record retention requirements.
63.10(b)(2)(i)–(xiv)	Yes.	
63.10(b)(3)	No.	
63.10(c)	Yes	Additional CMS Recordkeeping.
63.10(d)(1)	No	General Reporting Requirements.
63.10(d)(2)	No	Performance Test Results § 63.1567 specifies performance test reporting requirements.
63.10(d)(3)	Yes	Opacity or VE Observations.
63.10(d)(4)	Yes	Progress Reports.
63.10(d)(5)(i)	Yes	Startup, Shutdown, and Malfunction Reports. Except that reports are not required if actions are consistent with SSM plan, unless requested by permitting authority.
63.10(d)(5)(ii)	Yes	Except that reports of actions not consistent with the plan are not required within 2 and 7 days of action but must be included in next periodic report.
63.10(e)(1)	Yes	Additional CMS Reports.
63.10(e)(2)	No.	
63.10(e)(3)	No	Excess Emissions/CMS Performance Reports Subpart UUU specifies the applicable requirements.
63.10(e)(4)	No	COMS Data Reports.
63.10(f)	Yes	Recordkeeping/Reporting Waiver.
63.11	Yes	Control Device Requirements Applicable to flares.
63.12	Yes	State Authority and Delegations.
63.13	Yes	Addresses.
63.14	No	Incorporation by Reference.
63.15	Yes	Availability of Information/Confidentiality.

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