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Research Triangle Park, NC 27711

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June 2001
FINAL REPORT

Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units - Background Information for Promulgated Standards and Response to Comments

Final Report

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U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Waste and Chemical Process Group, MD-13
Research Triangle Park, NC 27711

Prepared Under Contract By:

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June 2001

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Environmental Protection Agency

Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units – Background Information for Promulgated Standards and Response to Comments

Prepared by:

Sally Shaver Director, Emission Standards Division U.S. Environmental Protection Agency Research Triangle Park, NC 27711	(Date)

1. The promulgated standards will regulate emissions of hazardous air pollutants (HAP) emitted from Petroleum Refinery process vents. Only those process vents that are part of major sources under section 112(d) of the CAA are regulated. The final standards will reduce emissions of several organic, inorganic, reduced sulfur, and metallic compounds identified in the CAA list of hazardous air pollutants.

2. Copies of this document have been sent to the following Federal Departments: Labor, Health and Human Services, Defense, Office of Management and Budget, Transportation, Agriculture, Commerce, Interior, and Energy; the National Science Foundation; and the Council on Environmental Quality. Copies have also been sent to members of the State and Territorial Air Pollution Program Administrators; the Association of Local Air Pollution Control Officials; EPA Regional Administrators; and other interested parties.

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4. Copies of this document may be obtained from:

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LIST OF ACRONYMS

API	American Petroleum Institute
bbl	Barrel
BID	Background information document
bpd	Barrels per day
CAA	Clean Air Act
CARB	California Air Resources Board
CCU	Catalytic cracking unit(s)
CEMS	Continuous emission monitoring system(s)
CO	Carbon monoxide
COMS	Continuous opacity monitoring system(s)
COS	Carbonyl sulfide
CPMS	Continuous parameter monitoring system(s)
CRU	Catalytic reforming unit(s)
CS_2	Carbon disulfide
D/F	Dioxin and furan
E-Cat	Equilibrium catalyst
EDV	Electrodynamic Venturi
EPA	Environmental Protection Agency
ESP	Electrostatic precipitator(s)
FCCU	Fluid catalytic cracking unit(s)
HAP	Hazardous air pollutant(s)
HCl	Hydrogen chloride
Hg	Mercury
H_2S	Hydrogen sulfide
MACT	Maximum achievable control technology

mg/yr	Milligram(s) per year
MW	Megawatt
NAAQS	National Ambient Air Quality Standard(s)
NESHAP	National Emission Standard for Hazardous Air Pollutants
Ni	Nickel
NO_x	Nitrogen oxide
NSPS	New source performance standard
O_2	Oxygen
OAQPS	Office of Air Quality Planning and Standards
pH	percent hydrogen (i.e., acidity or alkalinity)
PM	Particulate matter
POM	Polycyclic organic matter
ppm	Parts per million
ppmv	Parts per million by volume
ppmw	Parts per million by weight
psig	Pounds per square inch gauge
RFG	Reformulated gasoline
SO_2	Sulfur dioxide
SO_x	Sulfur oxide(s)
SRU	Sulfur recovery unit(s)
SSMP	Startup, Shutdown, and Malfunction Plan
THC	Total hydrocarbons
TOC	Total organic carbon
tpy	Tons per year
TRS	Total reduced sulfur
VE	Visible emissions
VOC	Volatile organic compound(s)

LIST OF COMMENTERS

Name	Affiliation	Docket No.
Chuck Ferrick	American Petroleum Institute	IV-F-3.1
Robert Morris	National Petrochemical & Refiners Association	IV-F-3.2
Donald Parus	Amoco Petroleum Products, Yorktown Refinery	IV-F-3.3 IV-D-55
Prasad Rao	Consultant/Economist	IV-D-24 IV-D-30 IV-D-32 IV-D-41 IV-G-1 IV-D-57
J. David Thorton	Minnesota Pollution Control Agency	IV-D-25
Edward J. Campobenedetto	Institute of Clean Air Companies	IV-D-26
Manisha D. Blair	Colorado Department of Public Health and the Environment	IV-D-27
William O'Sullivan, P.E.	New Jersey Department of Environmental Protection	IV-D-28
Ray Bishop	Oklahoma Department of Environmental Quality	IV-D-29
Lois N. Epstein, P.E.	Environmental Defense Fund	IV-D-31 IV-D-38
LaNell S. Anderson	Grandparents of East Harris County	IV-D-33
Eugene D. Becker	Global Sulfur Systems, Inc.	IV-D-35
Joel F. Wilson	Conoco, Inc.	IV-D-36
G.T. Theriot	Exxon Company, USA	IV-D-37
Jerry E. Thompson	Citgo Petroleum Corporation	IV-D-39
Thomas H. Jackson	Equiva Services LLC	IV-D-40
Ann Farner Miller	Tosco Corporation	IV-D-42

Name	Affiliation	Docket No.
Gary C. Furlong	Sunoco, Inc.	IV-D-43
James A. Ross	Phillips 66 Company	IV-D-44
Richard J. Glaser	Amoco Petroleum Products/Mandan Refinery	IV-D-45
Emily Green	Sierra Club Great Lakes Program	IV-D-46
William R. Beck	Mobil Corporation	IV-D-47
Allen R. Ellett	BP Oil Company/Toledo Refinery	IV-D-48
Norbert Dee, Ph.D	National Petrochemical & Refiners Association	IV-D-34 IV-D-49
Phillip T. Cavanaugh	The Chevron Companies	IV-D-51
Steven K. Pavel	Coastal Catalyst Technology, Inc.	IV-D-52
Karen Ritter	American Petroleum Institute	IV-D-53
R. Hermanson	Amoco Corporation	IV-D-54
Neil Carman, PhD	Sierra Club, Lone Star Chapter et al	IV-D-56
Kent Veron, P.E.	Marathon Ashland Petroleum	IV-D-58
Anne-Marie Ainsworth	Lyondell-Citgo Refining Company Ltd	IV-D-59
S. Eric Vrolenburg	Pennzoil-Quaker State Company	IV-G-2

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1.0 CONTROL REQUIREMENTS FOR CCU CATALYST REGENERATOR VENTS

1.1 Subcategorization of Thermal CCU

Comment: Commenters IV-F-3.2, IV-D-42, IV-D-49, IV-D-54, and IV-D-59 believe there are process and emission differences between the thermal (i.e., nonfluidized-bed) CCU regenerator vent and the fluidized-bed CCU regenerator vent that warrant subcategorization. They describe differences in process operations (flow pattern, operational severity, catalysts, regenerator methods) and control technology (technology for fluidized bed units is not applicable and there is no comparable proven control technology available). According to the commenters, designing and installing new, unproven control equipment would be difficult because the unit operates under very low pressure and the costs would be much higher. EPA has subcategorized CCU in all previous rulemakings, CCU monitoring requirements for organic emissions based on full burn vs partial burn regeneration, and semi-regenerative CRU based on operating processes and emission controls during regeneration processes. Subcategorization of CCU also would be consistent with European rulemakings.

Response: After a more in-depth examination and evaluation of this particular technology, we agree with the commenters that there are substantial technical differences in process operations of nonfluidized-bed CCU and fluidized-bed CCU that warrant subcategorization. These process differences include catalyst size and composition, as well as reactor operating characteristics (e.g., plug downflow versus fluidized riser processes, operating pressures). We also agree that the older nonfluid process of thermal cracking is not amenable to conventional particulate control technology, in large part because of the potential for back pressure as a result of control device operation. In addition, none of the three (3) existing thermal units identified in our database are equipped with air emission controls and we have been unable to identify any applicable air emission control technology that could be transferred to these type of CCU. The MACT floor for a thermal CCU subcategory is "no control," for both existing and new units, although it should be noted that it appears highly unlikely that any new units of this type would ever come on-line; the current trend is that these units are closing operations. Rather than subcategorize and set a standard based on no control for these units, the EPA has excluded non-fluid CCU from the requirements of the final rule.

1.2 Use of PM and CO as Surrogates for HAP

Comment: Commenter IV-D-46 believes EPA violates section 112 of the CAA by using PM and CO as surrogates for metal HAP and organic HAP. Section 112 requires emission standards for HAP listed for regulation, which does not include PM or CO. Although EPA calculates an alternative limit assuming that Ni is a surrogate for all other metal HAP, the agency selects the NSPS as the MACT floor without characterizing the proportion of emitted PM that are hazardous metals, non-hazardous metals, and unburned carbonaceous materials or the metals emission control performance of the PM emission controls in light of varying metal feed rate parameters. EPA did not characterize the relationship of HAP organics to CO. The commenter points out that during the Industrial Combustion Coordinated Rulemaking, EPA consultants explicitly state that CO alone could not be related to emissions of chlorinated dibenzo-dioxins/furans from combustion sources.

Response: It is important to note that the determination of MACT floors for CCU organic HAP and metallic HAP were based on the control technologies used in the industry, complete combustion of vent gases for control of organic HAP and an ESP or Venturi scrubber for control of metallic HAP. Surrogates were used in the standards only to characterize the performance of these best performing technologies. We have used surrogates for listed HAP in several rules because this simplifies compliance demonstrations by allowing the use of well-known methods, i.e., methods used to comply with the other CAA standards such as NSPS, and reduces costs associated with constituent analyses. In this case, we believe there is a strong justification for the use of surrogates. For the units regulated in this source category, the HAP emissions are contained in the same emission stream as the criteria pollutants subject to the NSPS and the control technologies and methods are the same. As discussed in Chapter 4 of the BID for the proposed standards, the CCU metal HAP emissions are primarily associated with the catalyst particles entrained in the CCU catalyst regenerator flue gas and the particulate emission control devices used to comply with the NSPS or other rules also provide metal HAP control. The EPA has documented that HAP metals that exist in PM form are readily controlled by PM control devices. PM is a reasonable indicator of HAP metals relative to control device performance. The final rule retains the optional use of PM as a surrogate for HAP metals because the MACT floor equipment and level of control for HAP metals, i.e., ESP and Venturi scrubbers, is identical to that for PM. Using PM as a surrogate for specific HAP metals eliminates the cost of performance testing to comply with numerous standards for individual metals, and achieves exactly the same level of HAP metal emissions limitation. The same basic argument holds true for organic HAP and use of surrogates.

The organic HAP emissions from CCU are contained in the same exhaust gas stream from CCU catalyst regenerator as any CO, THC or VOC emissions and all of these carbon-based emissions are a result of incomplete combustion in the catalyst regeneration step. The control methods for these pollutant types, including organic HAP, are the same, i.e., "complete combustion." The EPA has determined that for CCU, CO is a reasonable indicator of complete combustion. As for the comment that during EPA's Industrial Combustion Coordinated Rulemaking, EPA consultants explicitly state that CO alone could not be related to emissions of chlorinated dibenzo-dioxins/furans from combustion sources, the EPA feels that is point is not relevant to CCU because it is not expected that these units have D/F emissions. The currently available source test data all show D/F HAP levels that are below the test method detection limits; there are no data that confirm the presence of D/F HAP in the refinery CCU vent stream.

As for the other type of units regulated in this source category, no surrogate is used for HCl from CRU. COS and CS_2 are the main HAP emitted from the final sulfur plant vent and TRS is a reasonable indicator of these sulfur HAP. These reduced sulfur compounds are contained in the same sulfur plant vent emission stream as the SO_x subject to the NSPS and the control methods are the same (thermal and catalytic oxidizers). TRS is an excellent surrogate for these sulfur HAP compounds since reduced sulfur compounds consist of the two sulfur HAP plus H_2S (the nonHAP). TRS (expressed as SO_2) is a reasonable indicator of reduced sulfur HAP.

There are not sufficient data to establish a firm statistical relationship between PM and metal HAP, CO and organic HAP, and SO_2 and reduced sulfur HAP. However, since the MACT floor determinations were made based on the technologies in use at the units and the surrogates were used only to characterize the proper performance of the units, a precise statistical relationship between surrogate and HAP is not necessary in this particular situation.

1.3 NSPS as MACT Floor

Comment: Commenters IV-D-26, IV-D-31, IV-D-46, and IV-D-56 believe EPA violates the CAA by using the NSPS as the MACT floor for existing and new sources. The EPA analysis does not articulate the average performance of the top 12 percent of units (by PM/CO or metal/organic HAP) or the best performing source. EPA instead sets the standard for new and existing sources as the NSPS rate on a not-to-be-exceeded basis. For existing sources, EPA should establish specific metal HAP emission rates based on the average of the best performing five metal emission rates for each metal HAP and for the control for organic HAP. For new sources, EPA should establish the standard based on the best performing unit.

Commenters IV-D-26, IV-D-31, and IV-D-56 state that the proposed HAP metal emission limit adopted from the NSPS (1.0 lb of PM per 1,000 lbs of coke burn-off) is less stringent than the allowable MACT floor and does not reflect the level of control already met by more than 12 percent of existing sources using an ESP, Venturi scrubber, or fabric filter. They point to EPA data for 26 units which reflect a median emission rate of 0.81 and a mean of 0.86 lb per 1,000 lbs of coke burn-off. These commenters urge EPA to lower the proposed limit to 0.81 lb/1,000 lb of coke, the median PM emission rate in the database.

Response: In determining MACT, the EPA can consider alternative approaches for establishing the MACT floor; these include: (1) source test data that characterize actual emissions discharged by the sources, (2) use of a technology and an accompanying demonstrated achievable emission level that characterizes the technology and accounts for process and air pollution control device variability, and (3) information on Federal and State regulations and/or permit conditions that apply to the source.

If the information gathered indicates that more than 12 percent of the existing units or sources are currently subject to the NSPS for that source category and no more stringent rules apply, the NSPS thus represents the average emission limitation achieved, in terms of a regulatory requirement, by the best performing 12 percent of existing sources.

The commenters' points were recently addressed by the D.C. Circuit in *Sierra Club v. EPA* (March 2, 1999). That case holds that EPA can reasonably interpret the MACT floor methodology so long as the Agency's methodology in a particular rule allows it to "make a reasonable estimate of the performance of the top 12 percent of units" and that evaluating how a given MACT technology performs is a permissible means of estimating this performance. In developing emission limits, EPA cannot establish a limit based on the median value only, without allowing for the achievability of that limit in practice. The EPA believes that the NSPS levels selected to characterize the MACT floor performance adequately account for the variability inherent in the processes themselves and the air pollution control technologies, and indicates what levels are consistently achievable in practice.

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 of metallic HAP. No technology has been demonstrated in this industry to provide a level of control more stringent than the MACT floor for metallic HAP.

1.4 Extension of the Compliance Date

Commenters IV-F-3.2, IV-D-35, IV-D-39, IV-D-43, IV-D-44, IV-D-47, IV-D-49, IV-D-53, IV-D-54, IV-D-59, and IV-G-2 urge EPA to defer or delay promulgation of the inorganic HAP standards for CCU catalyst regeneration vents to allow time to coordinate the rule with development of the Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements other rulemakings such as RFG Phase II, and NAAQS PM standards. Achieving the sulfur reductions under Tier 2 will, in many cases, result in additional modifications to the unit and possibly pretreatment of its feed to reduce the sulfur or nitrogen content, which is expected to reduce metal HAP emissions if the reductions are severe enough. Other recommendations include extending the compliance date until the compliance date for Tier 2 fuels or 1 year afterwards, extending the compliance date to 6½ years from the compliance date for the final rule, and deferral for an unspecified period. The major concern voiced by the commenters is that plants will be required to install expensive controls that may be extraneous as soon as they are installed depending on the outcome of these and other rulemakings. Because of the low emissions and risk, the impact on the environment would be minimal, if any at all.

Response: We agree that the Tier 2 rule will also affect the refinery production processes and may affect the volume, characteristics, and environmental fate of pollutants now emitted by refineries.

To comply with the Tier 2 gasoline sulfur control requirements, individual refineries ultimately will need to produce gasoline with an average sulfur content of 30 ppm. The majority of refineries will need to undertake major construction projects to meet this limit. Since these projects could require modification of CCU and other affected sources, we revised the schedule to delay promulgation of this rule until completion of the Tier 2, which was promulgated on February 10, 2000 (65 FR 6698).

For some refineries, the Tier 2 rule significantly impacts its CCU. These refineries will have construction projects adding hydrotreating of the feed to the CCU. For these refineries, we extended the compliance date to allow more time for construction projects. We believe that this will encourage refinery owners and operators to employ hydrotreating of the feedstock to comply with the Tier 2 rule. As discussed in more detail below, we believe that hydrotreating the feedstock has increased environmental benefits relative to other methods of reducing gasoline sulfur.

The extended compliance date for existing CCU is based on when and how a refinery produces low sulfur gasoline to meet the Tier 2 limit. Hydrotreating the feed to the CCU is one of the means of producing low sulfur gasoline. As discussed further below, hydrotreating the feedstock provides environmental benefits not realized with other methods of producing low sulfur gasoline. It is also, unfortunately, significantly more expensive than other methods of reducing the sulfur content of gasoline.

A refinery owner or operator must determine which technology to use in reducing gasoline sulfur to meet the fuel standards. A number of alternatives are available. Refineries may elect to hydrotreat after the CCU, hydrotreat the CCU feedstock, or implement some other form of desulfurization technology. Hydrotreating the feedstock removes metals as well as sulfur. While hydrotreating the feedstock to the unit would allow greater flexibility within the overall refinery operations and would better position the refinery for any additional sulfur fuel standards that might be promulgated in the future, such as standards to reduce sulfur in diesel fuel (64 FR 26142, May 13, 1999), the cost of hydrotreating the CCU feed is considerably more than post-unit hydrotreating for desulfurization. Thus, despite the greater flexibility realized through hydrotreating the feedstock, there is an economic bias against its use to reduce gasoline sulfur to meet the fuel standards. We believe that this bias could increase substantially if we do not coordinate the compliance dates for this NESHAP and the Tier 2 rule. A substantial increase in the economic bias against hydrotreating the feedstock would likely result in less refineries implementing this method of reducing gasoline sulfur, thereby foregoing a potentially significant environmental benefit.

Some facilities will take longer than 3 years to comply with the Tier 2 standards. Should these facilities elect to install hydrotreatment units for the feed to the CCU, these new units will not be operating at the compliance date for the MACT standard, 3 years after promulgation. To avoid noncompliance, an owner or operator would be required to install expensive PM controls to comply with the MACT standard. These new controls might then become redundant with the later startup of the hydrotreatment unit for the feed to the CCU. Therefore, if the owner or operator elects to install a hydrotreatment unit for the feed to the CCU, the MACT compliance date for the CCU becomes the same as the Tier 2 compliance date.

Linking the compliance dates for the two rules, in this particular instance for those refineries that elect to hydrotreat the CCU feedstock, will allow the refinery to coordinate both decision making and the actual construction projects and, thus, minimize disruption to the refinery operations. We believe that not linking the compliance dates for the two rules could result in an environmental benefit being foregone and that linking them will result in a net environmental benefit because the number of process unit shutdowns and startups would be minimized. Shutdowns and startups can result in considerably more emissions to the atmosphere than operations under normal conditions. An estimate of the emissions reductions that would result from linking the compliance dates for the CCU standards and Tier 2 fuel standards is not possible at this time. This is because we lack information regarding how the refineries will choose to comply with the fuel standards and the uncertainties associated with startup and shutdown of these refinery operations.

Linking the CCU compliance date to the Tier 2 fuel standards' compliance date (i.e., the date the refinery produces low sulfur gasoline at 30 ppm) will not result in an overall or complete delay of the MACT standards for all CCU. While we believe that linking the compliance dates will serve as an incentive to hydrotreat the CCU feedstock, we nevertheless expect that the majority of facilities will comply with the fuel standards without implementing CCU feedstock hydrotreating. In some cases, even those that elect to hydrotreat the feedstock will comply in 5 years or less to take advantage of the various pooling, averaging, banking, and trading options provided in the final Tier 2 standards. The remainder of refineries will begin production of low sulfur gasoline over the next 10-year period, although most are expected to be in full compliance (i.e., producing gasoline at the 30 ppm annual average) by the year 2006. In no case will refineries be allowed any later than December 31, 2009, to comply with the standard for CCU, which corresponds to the final Tier 2 compliance date.

1.5 Hg Emission Control

Comment: Six commenters (IV-D-30, IV-D-25, IV-D-26, IV-D-31, IV-D-46, and IV-D-56) urge EPA to reconsider its determination not to regulate Hg emissions, conduct a review of available data and technology, and establish standards for Hg emissions from CCU regenerator vents. According to Commenters IV-D-30, IV-D-31, and IV-D-56, EPA is incorrect in its determination that no technology that controls Hg has been shown to be applicable to emissions from CCU regeneration vents. EDV scrubbers may control Hg when appropriate modules are attached. Commenter IV-D-26 agrees that while PM controls will reduce a certain portion of the Hg, emerging technologies are becoming available to control gaseous Hg emissions; EPA should review available data, correlate emissions to coke-burn rate, exhaust rate, throughput, the presence or absence of upstream pretreatment such as hydrotreating, and to the Hg content of the crude oil. Otherwise, EPA should defer the Hg portion of the rulemaking until more research is conducted.

Commenters IV-D-31 and IV-D-56 specifically ask EPA to evaluate MACT for existing sources based on the lowest crude Hg content used by the top 12 percent of existing refineries and MACT for new sources based on the lowest Hg content crude oil available that still meets refinery performance characteristics. This commenter also notes that since the preamble states that use of feedstocks with lower metal content is a form of pollution prevention, this rationale also applies to Hg.

Commenters IV-D-46 and IV-D-56 believe EPA erred under section 112 and abused its discretion in determining that uncontrolled Hg emissions constitute the MACT floor. These commenter argue:

- The MACT floor for existing sources should be the average of the best performing 5 sources or 2.75×10^{-2} lbs of Hg per mm bbl. New source MACT should be equal to the best performing source in the Hg emissions database, 1.00×10^{-3} lbs of Hg per mm bbl. *[Note: EPA database shows 0.443 and 0.07, respectively for these two numbers]*

- EPA must consider technology transfer and pollution prevention control techniques as part of a beyond the floor determination. In support, the commenter cites language from the Senate Committee Report on the standard setting process, with emphasis on the "top-down" process. According to the commenter, consideration of "top-down" strategies in setting a beyond the floor standard is highly appropriate in cases of persistent, bioaccumulative toxicants, and technology transfer is a component in top-down PSD decisions, as noted in the legislative history. EPA can not dismiss the possibility of using technology transfer to control Hg emissions because no technology is presently used on the vents. The proposal contains no analysis to show that the application of methods derived by technology transfer would be technically infeasible. Use of spray dryer/fabric filter/carbon absorption technology should be technically feasible to control Hg emissions. Environmental benefits from more effective control of other toxic heavy metals also would occur. Baghouse particulate emission controls also would contain emissions which ESP can not control during upsets. Sodium sulfide injection was not considered or were pre-combustion Hg removal processes for gas-oil feeds to the CCU. EPA's failure to consider pollution prevention process and feedstock changes as they affect Hg emissions also violates the provisions of section 112(d)(2)(A), which states that EPA must consider in part, measures which reduce the volume of or eliminate emissions of such pollutants through process changes, substitution of materials or other modifications. Refiners using high Hg feed materials could switch to low Hg feedstocks or consider pre-CCU combustion and/or pre-distillation techniques for Hg removal.

Response: The EPA has conducted a review of available data and technology and has concluded that there are no demonstrated technologies that control volatile or gaseous Hg emissions from CCU regenerator vents. A supplier of EDV scrubber technology was contacted and source test and performance data documenting Hg removal efficiencies were requested. No data were received to substantiate or document the commenters claim of Hg removal. There are a number of emerging technologies that show promise in the control of these emissions but none have been shown to be applicable to CCU vents. (*See 1999 Critical Review - Mercury Measurement and Its Control, T.D. Brown, et al, AWMA June 23, 1999*.) Therefore, the MACT floor for Hg emissions for new and existing units is no control. The comment that EPA should simply take the average of the best performing sources to determine the MACT floor for both new and existing sources ignores the fact that no control technique could be identified for the units with the lowest Hg emissions. Without identification of a Hg control technique, a standard based on the best five performing units for existing sources and the best single performing source in the Hg emissions database would not be achievable in practice across the industry. In addition, the values or limits reported by the commenter are inconsistent with the available source test data in the current refinery vent database.

The EPA has also examined pollution prevention and source reduction control techniques for Hg emissions control. EPA agrees that pre-treatment techniques such as hydrotreating the CCU feed would have an impact on Hg and other HAP metal emissions. We collected additional data after proposal to assess the environmental impacts and performance of hydrotreatment, including Hg removal, but currently available data are not adequate to characterize the precise Hg removal that could be expected and what factors in the processes influence these removal rates.

1.6 Fabric Filters as MACT Floor or Beyond the Floor Technology

Comment: Commenters IV-D-30, IV-D-31, and IV-D-56 do not agree with EPA's preamble statement that "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." They point out that EPA only acknowledges wet scrubbers and ESP for controlling particulates and metal HAPs when fabric filters are in wide use and far more effective for particulate and metal HAP. The EPA must acknowledge this technology as a potential control device and evaluate its applicability for metal HAP control on FCCU regenerator vents.

Response: We agree with the commenters that fabric filters are typically used for the control of particulates and HAP metals. However, this technology is not in use in this industry in large part for technical reasons such as the high temperature of the gas stream that impacts operation and operating costs, and the more frequent down time for this type of control device again associated with maintenance. In fact, we are aware of only one plant that is reportedly using this control method. At this plant, the CCU vent control configuration includes heat recovery, a dry lime scrubber, and a baghouse. The smaller CCU at the refinery is a residual oil CCU (referred to a the ROSE unit) and was designed to process very poor quality crudes. The dry lime scrubber was included in the process design to remove sulfur (i.e., SOx) from the CCU catalyst regeneration vent flue gas. The baghouse was included in the process design to remove the lime from the flue gas after the dry lime scrubber. That is, the baghouse was not installed to control PM emissions from the CCU but rather lime dust emissions from the lime scrubber. The PM loading to the baghouse, for this control scenario, is primarily lime dust entrained from the dry lime scrubber. The baghouse itself is a 12 compartment baghouse with 400+ bags per compartment. The facility operator sights operational difficulties both with the dry lime scrubber (lime handling area and disposal) as well as baghouse operation (leak detection and repair) in addition to high operating and maintenance costs. Based on this information and other factors EPA does not consider this control system to be the"best of the best" performing technologies for reducing HAP emissions from the CCU regenerator vent. These technical considerations would make the application of this air pollution control technology to this industry somewhat uncertain. Performance in this type of application is not demonstrated or documented. Wet scrubbers and ESP are the dominant control methods for metal HAP (PM) emissions from FCCU and clearly comprise the MACT floor technology.

1.7 Ni Alternative Standard (lbs/hr)

Comment: Three commenters (IV-D-45, IV-D-53, and IV-D-54) believe EPA should relax the proposed CCU metal HAP standard that is formatted in terms of lb/hr. For small refineries that emit relatively small levels of Ni, they recommend a limit in the range of 100 to 200 grams per hour. Commenter IV-D-45 suggests this limit should be averaged over a rolling 12 month averaging period, with compliance determined by periodic E-Cat analyses, analyzed by third parties, and material balance on the FCCU catalyst. Since catalyst is added in batch steps, weekly or monthly measurements are not reliable and a longer averaging period is needed to smooth the data to a reliable average. According to the commenters, the proposed limit (13 grams per hour) is based on a select group of the best-performing FCCU with low Ni feed that use feed hydrotreaters and are subject to other stringent regulatory requirements. It cannot be concluded that the performance of this subset is equivalent to the MACT floor technology.

According to Commenters IV-D-53 and IV-D-54, EPA's variability analysis also is flawed because EPA uses: (1) the z-statistic rather than the student's t-statistic, which is appropriate for small samples from populations, (2) the average relative standard deviation instead of the more representative maximum relative standard deviation, (3) data known to be false or problematic, and (4) the 95% confidence level rather than the 98% interval, which the commenter claims is an EPA precedent. This commenter also believes the level of emissions excluded by the standard is trivial and of little environmental significance. Raising the alternative standard would allow some refineries to avoid installing controls that are not cost effective and provide real *de minimus* relief. The commenters support a standard of 0.38 tpy based on this approach.

Commenter IV-D-49 and associated industry commenters supports the alternative standard but believes that the limit should be revised to include the variability of Ni concentrations within the same crude. They contend that this option is not available to all facilities because a refinery can not easily change its crude oil or the feed composition to the unit to one with low Ni to meet the standard. The standard is set at the extreme low end of the range of Ni emissions from California refineries based on the combination of low Ni crude oil and hydrotreating of feedstocks. This commenter cites U.S. Department of Energy data showing that outside California, 30% of the industry hydrotreat CCU feed. The percentage of units with the combination of hydrotreating and low Ni crudes is far less than 30% due to the limited availability of low Ni crude. For these reasons, EPA needs another alternative that is not more restrictive on large units than small units.

Commenters IV-D-30, IV-D-31, and IV-D-56 oppose the proposed alternative (0.029 lb/hr of Ni). According to these commenters, this option does not control particulate emissions, the use of Ni as a surrogate poses difficulties in monitoring and ensuring compliance, and it inadvertently allows medium and large units to escape control. They point out that, while this option provides flexibility to small units, units with a coke burn capacity less than 25,000 lbs/hr will not need to install controls and even medium to large-sized units could comply with a third-stage cyclone. EPA appears to be exempting the very population of units that is currently uncontrolled (small and medium-sized refineries that have been grandfathered or otherwise have escaped regulation). Since most large units have at least a high efficiency third-stage cyclone, they also could comply with this option. If it is EPA's intent to provide relief to small operators, the alternative should be limited to units with a coke burn capacity less than 15,000-20,000 lbs/hr at facilities that are classified as small entities. Or, EPA could promulgate a PM lb/hr standard which would control both metal HAP and particulates and make more sense for units with low Ni content in the feed. The commenter suggests that a standard of 20 lbs/hr per 1,000 lbs of coke burn-off would ensure that only the smaller units (less than 20,000 lbs of coke burn per hour) are provided flexibility. Another solution is to supplement the Ni standard with a PM standard (e.g., 0.029 lb/hr of Ni and 20 lbs/hr of PM) since this would focus only on small units, effectively control metal HAP and PM, and yet is more lenient and less expensive than the PM NSPS.

Response: The data available to EPA indicates that 12 percent of the refinery industry meets an emission limitation of 0.029 lb/hr (0.125 tpy), which was used to characterize performance of the MACT floor technology. The emission limitation in this format was selected to provide additional flexibility to the own/operator and was meant to provide a means for the owner or operator to demonstrate compliance regardless of what combination of treatment and operational practices were used to achieve the emissions limit. It is also important to note that each compliance option within a particular standard does not need to be available to every refinery; all refiners can comply by installing the MACT technology. The EPA rejects the 100 to 200 grams per hour limit suggested by some commenters. These high limits are provided without any supporting documentation and appear to be selected on the basis of emission values higher than 90% of the refinery industry.

We acknowledge the quality assurance concerns regarding the results of certain Ni emission measurements and the use of larger confidence intervals about the average emission value in setting an emission limit that reflects use of the MACT floor technology. However, we also believe that the analysis must use the average of the top 12 percent or the 6th percentile facility, rather than the emissions of the 12th percentile facility. There are 124 FCCU in the U.S. and its territories; the 6th percentile of the industry would be represented by the emissions reductions achieved by the 7th and 8th ranked units. Reanalysis of the data, considering the reviewer's comments on the statistical approach while using the 6th percentile unit, yields an emission limit nearly identical to the proposed limit.

In response to this comment, we examined the emission rates of the top performing unit for which we have documented source test results. We found that the average emission rates, as well as each individual test run result for the top 8 ranked units, are all below 200 lbs/yr. The 9th and 10th ranked units have similar average emission rates, but a wider fluctuation in the individual test run results. From the test data available, we determined that the proposed emission limit of 250 lbs/yr adequately characterizes the performance of the MACT floor technologies while taking into account process variability. For these reasons, we made no change in the proposed Ni lb/hr emission limit.

The EPA considers the Ni emission limit alternative standard to be both useful and necessary. The purpose of the MACT program is to control HAP emissions. Although PM control is strongly related to metal HAP emissions, it is only one of the two primary factors. If the refinery operates with low metal HAP E-Cat concentrations and relatively low PM emissions, additional PM emission controls may be an ineffective and unnecessary requirement to ensure low metal HAP emissions. Consequently, no limitation of this second metal HAP emission limit is required or justified in order to exact some additional level of PM control on facilities that otherwise meet the metal HAP MACT floor (as measured using Ni as the surrogate). In short, no PM controls are required if a unit meets the Ni standard.

1.8 Ni Alternative Standard (lbs per 1,000 lbs of coke burn-off)

Comment: Fourteen commenters (IV-F-3.1, IV-F-3.2, IV-F-3.3, IV-D-37, IV-D-39, IV-D-40, IV-D-43, IV-D-44, IV-D-47, IV-D-48, IV-D-49, IV-D-53, IV-D-54, and IV-D-59) urge EPA to include a rate-based Ni alternative of 0.006 Ni/1,000 lbs of coke burned in the final rule. The commenters support the approach of using a direct conversion factor based on FCCU fines data to convert the proposed PM emission limit in lbs PM /1,000 lbs of coke burn to a Ni emission limit alternative. According to the commenters, this format avoids penalizing large units with low HAP emissions and the conversion factor approach better equates to the NSPS PM standard. The first Ni alternative (a mass-based format in lb/hr) is representative of the lowest emitting sources, regardless of processing capacity and cannot be related to the rate-based (lb/1,000 lbs of coke burn-off) PM standard that recognizes the wide variety of processing capacity within the industry. Most of the units that can comply with the PM standard cannot comply with the mass-based standard due to their greater size. Larger units should not be subject to a more restrictive Ni limit than smaller units due to their greater processing capacity.

Commenter IV-D-49 explains that the relationship between the PM Ni content and the E-Cat Ni content is roughly 1 to 1, the key factor being the Ni E-Cat concentration. In the proposal preamble, the EPA recommended using a value of 1,300 ppmw which is the average of Ni fines concentrations and results in an emission rate of 0.0013 lb Ni/1,000 lb of coke which the commenters contend is not achievable by all facilities equipped with MACT floor technology. They note that some refineries can not easily change crude oil or feed composition to low Ni to meet the standard at this level as the Ni content of crude oils varies widely, as do emissions. The commenters argue that to ensure the standard is achievable by all facilities with an ESP or scrubber, EPA must use the highest Ni content of any operating FCCU, (6,833 ppm). Based on industry data, the Ni on the fines is about 0.87 times the Ni on the E-Cat, which yields the 0.006 value for the alternative Ni standard in lbs/ 1000 lbs coke burn. Commenter IV-D-33 agrees with the need for an alternative standard due to the high cost of control for a CCU regenerator with low Ni emissions and supports the industry proposal for an alternative standard of 0.006 lb of Ni per 1,000 lbs of coke burn calculated using the highest or worst-case Ni E-Cat value for the conversion of PM to Ni. The commenter believes this approach is technically and environmentally defensible as the MACT floor standard. Commenter IV-D-33 would support a slightly more stringent standard provided EPA accepts industry comments on the methodology used to calculate the Ni mass standard. Commenter IV-D-44 supports the industry-recommended alternative, even though 6,833 ppmw E-Cat Ni concentration used to establish this standard is not a maximum and may limit operations. Commenters IV-D-47 and IV-D-48 supports the rate-based option provided it reflects current operating conditions with the industry including normal variability in the crudes that are processed.

On the need for and usefulness of a second nickel standard, Commenter IV-D-48 believes the API-recommended standard determined using the worst-case conversion factor is reasonable. Using the EPA recommendation of the average E-Cat value, this commenter estimates 45 refineries would be required to install controls at a cost of $48 million/yr to reduce HAP by 38 tons per year. With an alternative Ni standard at the level recommended by the industry (using the highest or worst-case E-Cat), 6 refineries would install controls to reduce HAP by 19 tons per year at a cost of $6.5 million/yr. Use of the worst-case value will still require large HAP sources to control emissions and would be more cost effective.

Commenters IV-D-30, IV-D-31, and IV-D-56 strongly disagree that EPA should provide the second Ni alternative at the level suggested by industry (i.e., 0.006 lbs per 1,000 lbs of coke burn). They state that this alternative is not technically equivalent to the MACT floor, is not protective of the environment as it is set at a level that allows all refiners to process heavy feeds with no control device, and it is difficult to enforce. Many refiners with nickel E-Cat levels an order of magnitude below 7,000 ppmw (the highest Ni on E-Cat level in the database) would not require any particulate controls and most others could comply with only a third stage high efficiency cyclone rather than the MACT floor technology. Based on EPA data and analyses, the average nickel on E-Cat is less than 500 ppmw. Additionally, many refiners process virgin gas oil or hydrotreated feed low in metals. The Ni on E-Cat in these cases is less than 1,000 ppmw. The commenters contend that the actual Ni emission rate will increase under the industry's recommended worst-case approach and that a standard at the worst-case level could result in increased emissions of metal HAP and other pollutants (SO_x, CO_2, and PM) over time because refiners could process heavier feeds with higher Ni level, given the overall industry trend towards processing of dirtier crude.

Commenters IV-D-30, IV-D-31, and IV-D-56 also point out that the alternative format may present compliance and monitoring problems because refiners must change the feed frequently depending on product demand, crude prices and operating requirements and the Ni emission rate varies widely as a result. Under these conditions the refiner can not directly measure the Ni emission rate. To do so requires information on the coke burn rate, PM emission rate, and the instantaneous metal content of the catalyst inventory or the Ni content of the feed (all of which vary with time). Refineries also may trade the catalyst inventory so it may not be relied upon for computing the HAP metals emission rate. These commenters believe this additional option is an invitation to non-compliance and that a unit that demonstrates initial compliance may not be in compliance if it later processes a heavier feed.

Response: After careful review of all the information and data collected following proposal and received as part of the public comments, the EPA has decided to include an additional metal HAP alternative for CCU formatted in terms of Ni emissions per 1,000 lbs of coke burn. It has been concluded that this particular format (i.e., lb Ni/ 1,000 lbs coke burn) does account for the wide variation of processing capacity within the industry and provides adequate means of determining continuous compliance. However, it also has been concluded that the approach of using E-Cat Ni concentration to make a direct conversion of the PM emission standard to a Ni limit is not appropriate. The conversion factor approach does not lend itself to determining a Ni emission value that is technically equivalent or relates back to use of the MACT floor technology. The EPA has not been able to establish a rationale that would support the determination or derivation of a second alternative Ni emission limit value based on using the PM limit and the Ni concentration in the CCU catalyst fines to convert the PM mass to an equivalent Ni mass. Use of the Ni fines (or E-Cat) concentration as a conversion factor would not result in a emission limit that is technically equivalent to the MACT floor since the E-Cat Ni concentration in no way reflects the performance of the MACT floor technology. The Agency has no data or information to relate E-Cat metals concentration to the best performing facilities (i.e., E-Cat metal concentration does not reflect or relate to control device performance). In rejecting this conversion approach, the EPA is also rejecting the argument that a worst-case conversion factor is necessary or appropriate.

Nonetheless, the EPA feels that the alternative format in terms of lbs Ni/1,000 lbs coke burn has considerable merit even though the recommended approach to determining or calculating the specific emission limit based on an E-Cat conversion factor is not appropriate. This particular format allows for flexible compliance on the part of the FCCU owner/operator. A compliance option in this format is suitable for those large units that cannot, in some part because of their size, meet the lb/hr limit. An emission limit expressed in this format can be met by using front-end hydrotreating, in-process operational changes, or end of pipe add-on controls alone or in combination. We have therefore used the refinery database to develop a Ni emission limit in this particular format using an analysis based on the available emissions test data normalized in terms of coke burn rate. Although the currently available source test data is somewhat limited and is generally assumed to be representative of the lowest Ni emitters across the industry, it does allow an analysis to determine an appropriate emission limit to characterize the performance of the MACT floor technology following EPA's basic MACT floor determination criteria. This analysis thus provides an emission limit in the alternative format (Ni emissions per unit coke burn) that is reflective of the MACT floor technology.

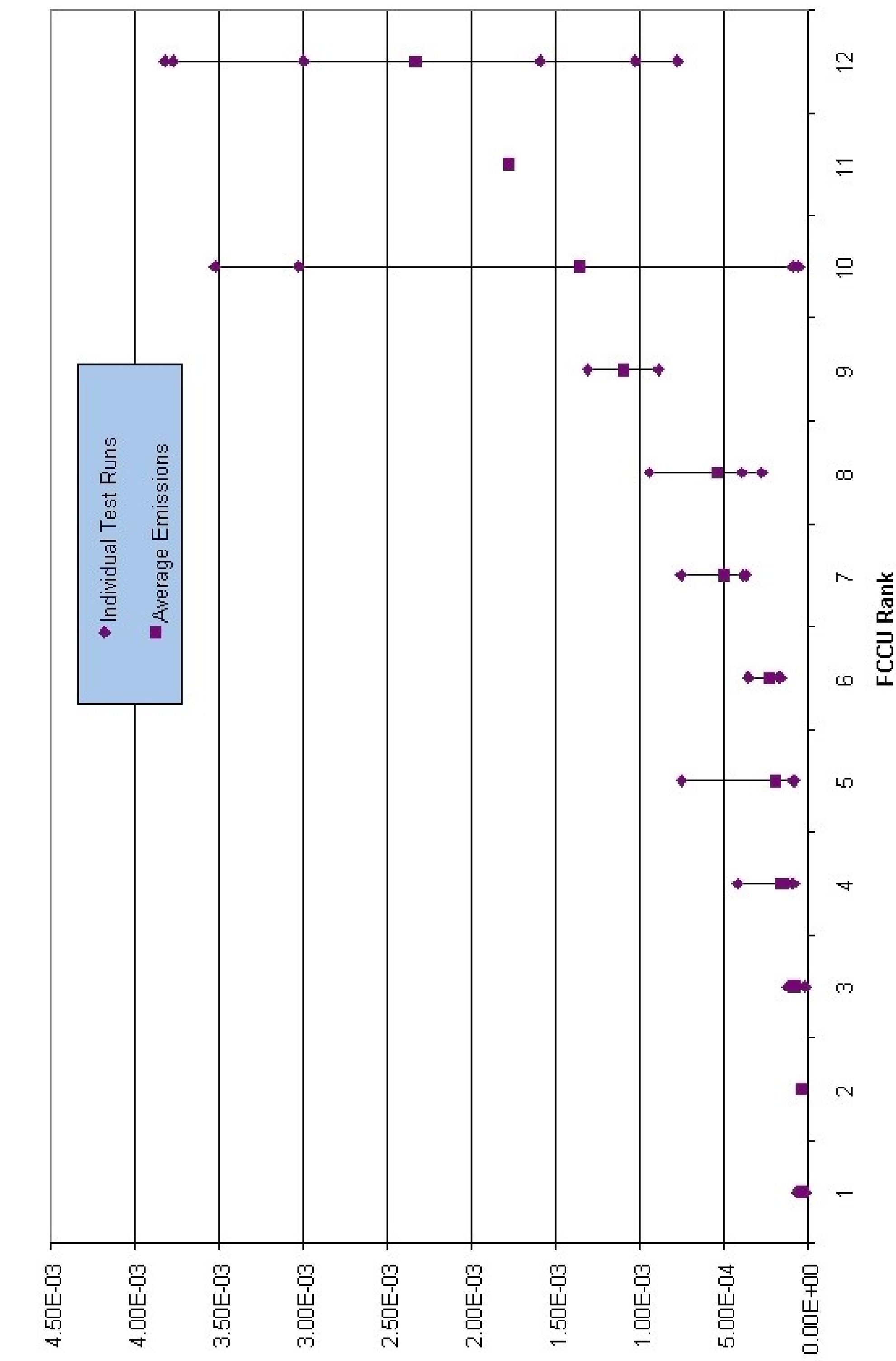
As there are 124 FCCU in the U.S. and its territories; the 6th percentile of the industry would be represented by the emission reductions achieved by the 7th and 8th ranked units. Through review of the emission data, we found that the average emission rates as well as each individual test run result for the top 8 ranked CCU are all below 0.001 lb Ni/1,000 lbs coke burn. The average emission rate for the 9th ranked facility is more than twice that of the 8th ranked facility. Therefore, only the top 8 units are considered in setting the emission limit. Based on our data analysis, we determined that the emission limit of 0.001 lb Ni/1,000 lbs coke burn adequately characterizes performance of the MACT floor technology while taking into account process and measurement variability (see Figure 1).   This analysis provides an emission limit in the alternative format (Ni emissions per unit coke burn) that is reflective of the MACT floor technology. This emission limit is included in the final rule as an alternative to the PM or Ni lb/hr limit.

1.9 Use of the Arithmetic Mean, Median, Geometric Mean, 90th Percentile Value, or Highest Value as the Representative Concentration Used in the Factor for Conversion of PM to Ni

Comment: According to Commenters IV-D-30 and IV-D-31, the relationship between PM emissions and Ni (or any other metal HAP) is best characterized by material balance equations which should be used instead of the statistical measures under consideration. Industry commenters generally contend that the highest value must be used. Commenter IV-D-48 contends that since all sources must be able to achieve a standard, EPA must choose the highest value of Ni as the representative concentrations used in the conversion from PM to Ni. The choice of the 90th percentile, the arithmetic mean, or the geometric mean would automatically exclude sources that have higher Ni concentrations from meeting any standard based on those levels without controlling their PM emissions to a lower level than the control technology of choice would allow. This would force those refiners to choose the PM standard instead of the Ni standard.

Response: As noted previously in comment/response 1.8, the EPA has decided to include an additional metal HAP alternative for FCCU formatted in terms of lbs of Ni emissions per 1,000 lbs of coke burn. It has been concluded that this particular format (i.e., lb Ni/ 1,000 lbs coke burn) accounts for the wide variation of processing capacity within the industry and provides adequate means of determining continuous compliance. However, it also has been concluded that the approach of using E-Cat Ni concentration data to make a direct conversion of the PM emission standard to a Ni limit is not the appropriate methodology to establish the emission limit in this format. The conversion factor approach is not technically equivalent nor does it relate to performance of the MACT floor technology. No rationale has been established that would support the determination or derivation of the second alternative Ni emission limit value based on using the PM emission limit that reflects the performance of the MACT control technology and the Ni concentration in the CCU catalyst fines to convert the PM mass to an equivalent Ni mass. Use of the Ni fines (or E-Cat) concentration at any value (highest, lowest, mean, or 90th percentile) as a conversion factor would not result in an emission limit that is technically equivalent to the MACT floor since the E-Cat Ni concentration does not reflect the performance of the MACT floor technology, as does PM emissions. The Ni E-Cat concentration of a FCCU are dependent on a complex mixture of operating and economic considerations.

Figure 1. Available Ni Emission Test Data for FCCUs in lbs Ni/1000 lb coke burn



The Agency has no data or information to relate E-Cat metals concentration to the best performing facilities (i.e., E-Cat metal concentration does not reflect or relate to control device performance).

The EPA has concluded that use of the worst case Ni E-Cat in a direct conversion of the PM limit to a Ni limit is in no way reflective of or linked to Ni emission control or the MACT floor technology. The EPA analysis indicates that an alternative standard based on the highest Ni E-Cat concentration to convert PM to Ni would require at most two facilities to add controls; the industry analysis shows the number of facilities adding controls dropping from 45 to six facilities. In addition, a standard at this high level could in the long term result in increased emissions of metal HAP rather than their control given the general trend in the industry to process lower quality crudes.

We have therefore developed a Ni emission limit in the particular format (lbs Ni/1,000 coke burn) that characterizes the performance of the MACT floor technology. The emission limit was determined based on the available emissions test data normalized in terms of coke burn rate using an analysis following basic EPA criteria for determination of the MACT floor. See comment/response 1.8 for more information on the alternative emission limit formatted in lb Ni per 1,000 lbs of coke burn.

1.10 Format of HAP Metal Standards

Comment: Commenters IV-D-30, IV-D-25, IV-D-28, IV-D-31, IV-D-56, and IV-D-57 urge EPA to change the format of the HAP metal standard for PM (lbs of PM per 1,000 lbs of coke burn-off) adopted from the NSPS, the HAP metal standard for Ni (lb/hr), and/or the HAP metal standard for Ni (lbs of Ni per 1,000 lbs of coke burn-off) on which EPA requested comments. All the commenters recommend that the standards use an output-based format expressed in pounds of pollutant per 1,000 barrels of feed or throughput to replace or supplement the proposed standards. Commenters IV-D-30 and IV-D-31 explain that the current format does not distinguish between units processing light feeds and those processing heavier feeds. This is important because units processing heavier feeds burn more coke per bbl of feed processed, which generates more emissions. The standard should be expressed in terms of emissions per bbl of feed based on the median quality of feed to the unit (i.e., the median pounds of coke generated per bbl). This would treat all units (including fluid and non-fluid units) processing feeds of different qualities equally and achieve better control of metal HAP, PM, and other pollutants such as CO and greenhouse gases. This would treat FCCU and non-fluid CCU equally and allow refiners additional flexibility in that they could use control devices, process better quality feed, and/or use catalysts that reduce coke formation. Commenter IV-D-25 points to the NO_x rule for new utility boilers, which ties the emission limit to the quantity of electricity produced rather than the quantity of fuel burned as precedent. According to the commenter, this revised format would allow facilities to address emissions from a broader viewpoint, encourage redesign of the process to achieve the emissions limit, and allow comparisons among different types of control equipment. Commenter

IV-D-28 does not believe the amount of coke burn-off, even if used in the NSPS, is the proper surrogate for HAP metals because it does not correlate well with the metal content of the feed. This commenter recommends a limit based on the HAP metal content of the feed (such as Ni), amount (bbl/hr) of feed processed, limits on catalyst fines exiting the regenerator, and particulate removal (over 99.9 percent). The maximum emission limit in lb/hr of Ni for each unit can be derived from maximum allowable E-Cat of Ni on emitted particulates and the maximum allowable lb/hr of particulate emitted.

Response: The EPA primarily requested comment on the format of the additional HAP metal standard being considered by the Agency, and as previously discussed, the EPA has decided to include an additional metal HAP alternative for the CCU in the format suggested at proposal, i.e., Ni emissions per unit of coke burn. With regard to the format recommended by the commenter, the EPA agrees that using CCU feed rate to normalize the emission rates from the CCU has certain advantages, as described by the commenters, for an additional metal HAP alternative emission limit. However, there also are disadvantages to this format as a replacement to the proposed PM and Ni emission limits and the new alternative format in terms of Ni per unit of coke burn. We evaluated a Ni emission limit in the lb/bbl format but concluded that the performance of the MACT floor technology is tied closely to the exhaust gas flow rate which is more directly a function of the coke burn rate than the CCU oil feed rate. The intent of the Ni emission limits, both in terms of lb/hr and lbs /1,000 lbs coke burn, is to require MACT control technology for CCU with high mass Ni emissions without undue burden on small refineries or those refineries that have low Ni emissions. The proposed formats and the new alternative Ni format are considered to accomplish this as effectively as possible. As such, no further change in the format of the proposed standards were made in the final rule.

1.11 Level of Proposed CO Limit for HAP Organics

Comment: Commenters IV-D-26, IV-D-28, and IV-D-56 believe the 500 ppmv CO limit is too high. Commenter IV-D-26 explains that although over 12 percent of the existing CCU are required to comply with the NSPS, no data is presented to indicate the actual performance level (according to the commenter). The commenter contends that this is contrary to section 112, which requires that MACT limits to be based on operating data from the top 12 percent. Because sources typically operate under their permitted limit, actual performance is probably under 500 ppmv. CO levels under 100 ppmv are readily available which is evidenced by the provision exempting them from monitoring if they demonstrate operation at less than 50 ppmv for 30 days. The 500 ppmv also fails to account for the lower operating efficiency that results in higher operating costs. Commenter IV-D-28 agrees and provides data in support showing that actual CO emissions from four refineries are all 50 ppm or under; actual CO emissions from one refinery with a 500 ppmv limit is 10 ppm. Organic HAP emissions even at the 50 ppmv level are significant as stack test results for a 54,000 bbl/day CCU show cyanide compounds of 4.8 to 5.2 lbs/hr and benzene emissions up to 1.6 lbs/hr. This commenter recommends a limit of about 100 ppm for normal operation. These levels can be achieved by using a low concentration oxidation catalyst in the regenerator in addition to complete combustion.

Commenter IV-D-54 disagrees. While EPA correctly concludes that more than 12 percent of the CCU are subject to the CO limit in the NSPS, there are no data in the record to demonstrate that these units can reliably and continuously meet the NSPS limit. EPA should review the periodic reports required by 40 CFR 60.7(c) to better evaluate this issue and consider averaging times longer than 1-hour for the final standard.

Response: We do not agree with the commenters who assert that the MACT floor must be based solely on operating data. The CAA requires a minimum level or "floor" for existing sources for categories or subcategories with 30 or more total sources that can be less stringent than the standards for new sources but cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources. After the floor has been determined, EPA must set standards that are technically achievable and no less stringent than the floor that can be met by all sources within the category or subcategory.

As discussed in the preamble to the proposed standard (see 63 FR 48899, September 11, 1998), individual constituent data for organic HAP were not sufficient to establish a MACT floor and could not be considered representative of the entire industry. For this reason, we reviewed emissions data on VOC, THC, and CO since these data are indicative of individual organic HAP. The emission data for CCU catalyst regeneration vents indicate that complete burn/combustion CCU and partial burn/combustion CCU followed by a CO boiler or other combustion device achieve similar organic HAP emission rates. As a result, both are considered types of "complete combustion." The NSPS CO emission limit requires FCCU to have complete combustion characterized and demonstrated by limiting the CO concentration to less than 500 ppmv on a not-to-be-exceeded basis. This CO concentration limit is determined by specific performance tests using EPA reference methods. Well over 12 percent of the existing CCU are subject to this NSPS limit. We feel that this limit represents the short-term average emission limitation achieved by the best performing 12 percent of existing sources.

We disagree that the limit needs to be set at a lower limit (e.g., 100 ppmv). First, a requirement for a lower CO limit presupposes that organic HAP emissions are further reduced at lower CO levels. The available emissions data do not support that supposition. Although the organic HAP emissions for CCU operating at or below 500 ppmv CO were significantly less than the organic HAP emissions for CCU operating above 500 ppmv CO, no reduction in total organic HAP is seen from 500 to 100 ppmv, based on the available data. As demonstrated by the data presented by the commenters, HAP emissions occur at all levels of CO within this concentration range. At the very low CO levels, it appears that aromatic HAP concentrations may be reduced but other HAP (e.g., formaldehyde) concentrations increase. Consequently, there appears to be little to no HAP emission reduction effected by requiring CO limits of 50 or 100 ppmv rather than the 500 ppmv limit.

Under the structure of the final rule, FCCU without an add-on control device, a combustion device in this case, would be required to install and operate a CEMS to monitor the CO emissions directly for compliance with the 1-hour standard of 500 ppmv. The 500 ppmv 1-hr average value was set in the 1973 NSPS specifically to accommodate complete-burn units. From the available CO source test data for non-NSPS units, it has been concluded that existing non-NSPS units should be subject to the same standard, i.e., they routinely achieve the 500 ppmv 1-hr average. The EPA went to the States to obtain additional data on partial-burn units and the limited data we received did not support a longer averaging time for these units. A longer averaging time would allow significant periods of operation at CO levels above 500 ppmv, which would reduce the HAP emission control efficiency for the unit.

The 500 ppmv limit is based on a short-term averaging time of 1-hour and is set at this value to account for process fluctuations and source test variability. That is, given a 500 ppmv limit evaluated on a 1-hour basis, refiners are forced to operate at much lower CO levels (e.g., 50 - 100 ppmv) to comply with the standard during process fluctuations. If the limit were based on a longer-term average, a lower limit could be selected that would be much closer to actual operating levels over the long term. However, commenters did not provide the historical data needed to analyze the alternative CO or averaging time limits. For these reasons, we did not revise the limit or the averaging time.

1.12 Format of Proposed CO Limit for HAP Organics

Comment: Commenter IV-D-25 urges EPA to adopt an output-based format using throughput to replace or supplement the proposed standard, pointing to the NO_x rule for new utility boilers as a precedent. This rule ties the emission limit to the quantity of electricity produced rather than the quantity of fuel burned. According to the commenter, this revised format would allow facilities to address emissions from a broader viewpoint, encourage redesign of the process to achieve the emissions limit, and allow comparisons among different types of control equipment.

Response: The EPA has determined that the concentration format (i.e., 500 ppmv for CO) that was proposed for control of organic HAP provides a reasonable and adequate characterization of the performance of complete combustion processes applicable to CCU, the MACT floor technology. This format is also consistent with the regulatory format of the NSPS for these units. Furthermore, the concentration format lends itself to direct measurement using a CEMS. The format recommended by the commenter, using unit throughput to normalize the emission limit, does not provide any advantages for this source category. It complicates compliance monitoring and it does not correlate as directly to the performance of the control technology. Therefore, we are confident that the proposed format for the organic HAP limits is adequate to characterize performance of the unit and to achieve a long term control of organic HAP emissions without restricting the operating flexibility of the unit.

1.13 Organic HAP Alternative to Proposed CO Standard

Comment: Commenter IV-D-54 believes EPA should include an organic HAP standard as an alternative to the CO emission limit for CCU. This standard could be in the range of 20 to 50ppmw, measured by Method 18 or 25. This would be a direct limit on organic HAP that bypasses the uncertainty of relying on CO as a surrogate. While the low CO content may serve as an indicator of complete combustion, it is not necessarily true that high CO content is a good indicator of high HAP emissions. This would be consistent with the MACT standard. The commenter notes that the lack of data precludes an opinion on whether the standard would be achievable or whether their company might elect to comply with an organic HAP alternative.

Response: We agree that a direct limit would be preferable to a surrogate approach. We considered the organic HAP standard as well as THC as an alternative surrogate but determined that we did not have adequate data to characterize all HAP species present in the CCU catalyst regenerator vent emissions. That is, few refineries tested for the complete array of possible organic HAP emitted from the CCU vent. As discussed earlier, we selected CO as a surrogate for organic HAP and the 500 ppmv limit of the NSPS to characterize or represent complete combustion, the MACT floor technology. The available data suggest that units operating below this CO level have comparable levels of organic HAP emissions.

1.14 SO_x and NO_x Emission Control

Comment: Commenters IV-D-30, IV-D-26, IV-D-31, and IV-D-56 urge EPA to include the NSPS standards for SO_x control in the MACT standards for CCU catalyst regenerator vents; two of the three commenters also advocate obtaining NO_x reductions. According to Commenters IV-D-30, IV-D-31, and IV-D-56, FCCU are one of the largest emitters of SO_x from refineries. An uncontrolled unit emits about 5,694 tpy of SO_x for a medium-sized unit with a feed sulfur content of 1% that burns 50,000 lbs/hr of coke. FCCU, particularly those operating in full combustion mode, also are large NO_x emitters. While the EPA SO_x program has established control requirements for SO_x from utilities and mobile sources, emissions from petroleum refineries remain unabated and may be increasing due to the use of more sour crude. They point to the SO_x health effects (morbidity as well as mortality) among sensitive population groups and to the environmental and economic benefits and that EDV scrubbers will control SO_x, NO_x, and volatile and semi-volatile metal HAP (e.g., cadmium, selenium, and mercury) that otherwise will escape control. The burden on small refineries could be reduced by allowing use of SO_x and NO_x-reducing catalysts or additives rather than the more costly add-on control equipment.

Response: While we understand that SO_x and NO_x emissions are of concern, EPA can not designate HAP standards under section 112 for the control of criteria or ambient pollutants regulated elsewhere under the CAA, e.g., criteria pollutants are subject to the NSPS requirements of section 111. Therefore, we did not include SO_x control requirements for FCCU.

We did investigate the EDV scrubber to determine its performance for HAP reduction. As previously discussed, no data were obtained to support the commenters contention that EDV scrubbers are effective for volatile metal HAP control.

1.15 Control of D/F Emissions

Comment: Commenters IV-D-38 and IV-D-56 urge EPA to incorporate a MACT standard for the control of D/F emissions from CCU regenerator vents. EPA is not meeting the requirements of the CAA if these emissions are not addressed in the final rule.

Response: First, the EPA was unable to confirm appreciable D/F emissions from the CCU vent. With the support of EPA, CARB conducted a detailed emissions source test at one complete combustion FCCU with no other post-combustion device in order to assess the potential of FCCU to emit dioxins, PCB and a variety of other HAP (both metallic and organic HAP). In this test, 6-hour sampling runs were employed to enhance the lower detection limits resulting from the analyses. Nonetheless, only the octachloro isomers of dioxin and furan were detected in the measurements. These are the least toxic of the D/F isomers; the mass emission rate of dioxins in terms of 2,3,7,8-TCDD toxicity equivalents (TEQ) for the detected D/F isomers ranged from 2 to 13 micrograms per year (μg/yr) for the three source test runs performed. Based on detection limits for those D/F isomers not detected during the test, the 2,3,7,8-TCDD TEQ is calculated to be 3 to 5 mg/yr. None of the PCB isomers were detected in any of the three stack samples collected for PCB analysis during the source test.

Similar test results were observed during a source test of a CO boiler processing FCCU exhaust gases. This CO boiler also received waste sludge from the wastewater treatment facility at the refinery; as a result this boiler was tested as a hazardous waste incinerator. The 2,3,7,8-TCDD TEQ emissions rate reported, largely based on detection limits, ranged from 2 to 10 mg/yr. The test summary data provided was not adequate to calculate the TEQ for detected isomers only, but the TEQ based on detection limits was similar to those measured during the CARB source test.

Based on the lack of significant detectable amounts of D/F and PCB measured during these source tests, and the lack of any other data to support that the FCCU contains a source of chlorine, which is necessary to generate dioxins, the FCCU was not considered to be a significant source of D/F emissions. Additionally, no significant difference was seen between complete combustion units with no post-combustion device and a partial combustion FCCU that employs a post-combustion device. Again, the lack of a source of chlorine is thought to be the primary reason for the low D/F formation in the CCU regenerator vent gas.

Second, the proposed MACT standard, although not directly developed for D/F emissions (because of the lack of verified D/F emissions), is considered by EPA to provide substantive D/F emission control. Section 112 authorizes the development of technology-based standards; MACT standards are based on the technology in use at the best-controlled facilities. D/F emission control may be effected by limiting chlorine, providing complete combustion, and/or effective PM removal (much of the D/F congeners condense onto PM). As chlorine is an unwanted contaminant in gasoline and may adversely affect CCU catalyst performance, the refineries have a built-in economic incentive to minimize the amount of chlorine that enters the CCU process. Beyond limiting chlorine, the MACT standard effectively establishes the requirements that should minimize D/F emissions, if any D/F compounds are generated. As none of the existing units regulated by the source category had specific D/F or other control systems in-place that had a higher demonstrated D/F removal efficiency than those required by the MACT standard, no HAP specific emission limits were proposed for these particular organic HAP.

Risk is not considered in determining the MACT technology. However, the CAA recognizes the high toxicity of 2,3,7,8 TCDFs and 2,3,7,8 TCDD in section 112(c)(6). In the event that D/F emissions were found to be higher than the current data indicate or if the currently projected levels of D/F emissions are found to have an adverse impact on human health of the environment (based on subsequent risk analyses), the residual risk posed by these HAP will be addressed in accordance with section 112(f)(2) within 8 years following promulgation of these standards.

1.16 Allowance or Exclusion of Emissions Created by CO Control Device

Comment: Commenter IV-D-49 and associated industry commenters ask EPA to include an allowance in the CCU catalyst regenerator vent standard for emissions created by the CO control device as is done in the NSPS. Combustion of the CO in a process heater or boiler will increase emissions of CO_2, NO_x, particulates, and possibly SO_2. The NSPS includes a variance for the additional particulates created by the control device. Without this, i.e., the allowance for secondary PM emissions, EPA costs for the CO control system will be underestimated by not accounting for the additional PM control. One commenter (IV-D-58) has a CCU catalyst regenerator vented to a CO boiler. The CO boiler uses a fluidized bed with limestone injection to remove SO_2. According to the commenter, the addition of limestone does not affect emissions of HAP metals so any nonHAP particulates resulting from the limestone addition should be excluded from compliance determinations.

Response: We have included an option in the final rule that allows the owner or operator to elect to comply with the NSPS limit and monitoring requirements, which includes the variance for additional PM generated by combustion operations used as control devices. We also revised the test requirements of the rule to allow measurements of PM ahead of the CO boiler or other process equipment rather than only at the exhaust vent. We believe this should resolve the commenter's concern about nonHAP particulates resulting from limestone addition as part of an air pollution control system.

1.17 Pollution Prevention Technologies for PM and HAP Metals from FCCU

Comment: Commenter IV-D-52 asks EPA to address the ACT™ and DEMET™ technologies as available and documented pollution prevention technologies that reduce the source of metal HAP emissions from fluid CCU. Technical papers are provided as support. According to the commenter, hydrotreating of the CCU feed was identified as a source reduction technique; although, it is an energy intensive high pressure hydrogen process which generates a hazardous waste and is physically disconnected from the CCU (*as are these two noted technologies*). The technologies are available and have been incorporated in the FCCU circulating catalyst system at one refinery to reduce PM and metal emissions.

Response: The EPA recognizes the ACT and DEMET technologies as potential technologies for reducing metal HAP content of the E-Cat and thereby reducing metal HAP CCU emissions. Similar to hydrotreating, these processes may help a refinery to meet the Ni emission limit alternatives (i.e., the Ni lb/hour limit or the Ni lb/1,000 lb coke burn limit) but no requirement specific for their use is included in the final rule.

1.18 Compliance Date for Retrofit Particulate Controls

Comment: Commenters IV-D-36, IV-D-43, IV-D-47, IV-D-49, IV-D-53, IV-D-54, and IV-D-59 recommend that a facility be allowed to schedule its compliance date for particulate standards for the CCU catalyst regeneration vent so that it coincides with the next unit turnaround after promulgation. According to Commenter IV-D-49, most facilities will request an extra year to schedule both the tie-in of controls and the normal turnaround at the same time. Although the extra year that can be requested will reduce some of the problem, there will still be a large number of facilities that will require an additional nonscheduled turnaround. It would not be desirable to force a significant part of the industry to shutdown because of the potential impacts on gasoline supply. Extra shutdowns, either to install equipment, new control tie-in points, or new control systems exposes the environment to additional emissions from startup and shutdowns and is very costly. Commenters IV-D-49 and IV-D-53 say EPA has granted similar delays in other rules and should allow 3 years plus 150 days. Commenter IV-D-43 suggests requiring controls for existing sources within 3 years of promulgation or the next scheduled major turnaround but no later than 6 years after promulgation. One commenter (IV-D-36) cites the typical turnout schedule of 3 to 4+ years, concerns regarding the availability of control equipment and qualified contractors, and similar extensions for other rules previously granted by EPA and requests 6½ years after promulgation. Commenter IV-D-54 recommends the first turnaround following three years of the date of publication of the final rule or by seven years from the date of publication.

Response: We have responded to these concerns in a number of ways. First, the new regulatory approach tied to Tier 2 , i.e., the switch of this rule to the 10-year bin provides plants additional time and the extended compliance date for those CCU that commit to use of hydrotreating to comply with the 30 ppm Tier 2 fuel standard. See comment/response 1.4 for additional discussion on the compliance date.

We also revised the performance test requirements to expand the period of time available for conducting the initial performance test. Under the final rule, you may conduct the initial performance test anytime after the effective date of the rule (the date of promulgation) rather than waiting until after the compliance date (i.e., 3 years after promulgation or 4 years if an extension is approved). As proposed, the notification of compliance status (which must include a copy of the performance test report and performance evaluation report if applicable) must be submitted no later than 150 days after the applicable compliance date.

1.19 Hydrotreatment of CCU Feed

Comment: Commenters IV-D-38 and IV-D-56 request that EPA evaluate catalytic hydrotreatment of CCU feed for inclusion in the MACT standards. As discussed in the BID for the proposed standards, this can reduce HAP as well as increase yield and catalyst life. Because this technology is in place at more than 12 percent of existing refineries according to U.S. Energy Information Administration data, it should be required as the MACT standard for all new and existing sources. Commenter IV-D-49 and associated commenters oppose EPA's description as a pollution prevention technique for the control of Ni emissions because hydrotreating increases emissions of CO_2, VOC, particulate, NO_x, and any HAP emissions associated with the combustion of carbon-based fuels. It also generates a RCRA-listed hazardous waste and the Ni removed from the feedstock to the CCU feed is transferred to the waste. This commenter also believes that under the definitions in the proposed rule, a hydrotreater meets the definition of a CCU.

Response: Since proposal of this rule, we have met with industry representatives many times to discuss how they will change the refinery production processes to meet the requirements of the Tier 2 and related distillates rule. It is clear that a variety of methods may be used. For example, plants that currently hydrotreat or hydrocrack the feed to the CCU may increase the severity of treatment to reach the 30-ppm sulfur level required by the Tier 2 rule. Other plants may treat the distillate stream after the CCU to reduce the sulfur content which will not impact emissions of HAP metals. Either approach will increase the throughput of sulfur discharged to the SRU.

We have collected additional data and information since proposal to better assess the environmental impacts and performance of hydrotreatment. The metal HAP emission rate from the CCU catalyst regeneration vent can be attributed to two general factors: (1) the metal HAP content in the circulating CCU catalyst particles (i.e., the E- Cat concentration); and (2) the mass rate at which these catalyst particles are entrained in the flue gas and emitted to the atmosphere. As discussed previously, PM emission controls have a direct bearing on the second factor, i.e., PM emission rate, and therefore the metal HAP emission rate at a constant E-Cat concentration. Hydrotreating has a much less direct affect on the metal HAP emission rate. As discussed in the BID and as pointed out in the comments, hydrotreating both reduces the metal HAP content of the CCU feed and it increases catalyst life. With the increased catalyst life, the operator, in some situations, can lower the catalyst replacement rate which tends to increase E-Cat metal HAP concentrations, and tends to negate or off-set much of the effect of the lower metal HAP feed content's impact on CCU metal HAP emissions. E-Cat Ni concentrations were examined for refineries that hydrotreat their CCU feed. The data varied over a considerable range and were comparable to the Ni E-Cat concentrations for nonhydrotreating units. More importantly, hydrotreating technology is not applicable or available to all refinery configurations. As such, hydrotreating alone could not be considered a MACT floor technology to reduce metal HAP emissions from the CCU catalyst regenerator vent.

The EPA also gathered additional technical information regarding hydrotreating as a potential source reduction measure (or technology for removal of metal HAP prior to the CCU). Under the Tier 2 emission standards for vehicles and gasoline sulfur standards for refineries, refineries would be required to make cleaner gasoline, i.e., with a lower sulfur content. Hydrotreating of CCU feedstock is one way of reducing the sulfur content of gasoline and the refinery industry's decision on how to meet the fuel standards also impacts their decision on how to meet the MACT standards for CCU.

Hydrotreating (and hydrorefining) is a process used primarily to remove sulfur from various refinery process feedstocks. The process involves mixing the hydrocarbon stream with hydrogen in the presence of a catalyst at high pressures (800 to 2,000 psig) and high temperature (700°C). The level of sulfur removal is generally 80 to 95% depending on the "severity" of the process. Severity is increased with increased operating temperature and hydrogen partial pressure, and lower space velocity (which increases contact time with the catalyst). With respect to catalytically removed components, sulfur is the preferentially removed. After approximately 80 to 90% sulfur removal, nitrogen removal begins, and after that, saturation of aromatic hydrocarbons.

1.20 Other Associated Emission Sources

Comment: Commenters IV-D-30 and IV-D-56 identify catalyst particles released during loading and unloading of the catalyst inventory as a potential emission source to be evaluated.

Response: We have no data on emissions from this activity and can not assess it quantitatively. However, the EPA did examine these sources during the information gathering stage of this rulemaking and it was judged that these sources were not significant and as such did not warrant inclusion in the standards. We will gather additional information following promulgation of this rule as part of the rule development process for residual risk standards.

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2.0 CONTROL REQUIREMENTS FOR CRU CATALYST REGENERATOR VENTS

2.1 MACT floor for Semi-Regenerative CRU vs Exclusion of Control Requirements

Comment: Commenter IV-D-26 opposes the MACT floor determination for semi-regenerative units, which he believes is substantially less stringent than for the cyclic or continuous type units. The proposed limit is erroneously based on the 92% efficient single stage scrubber (the lowest HCl control efficiency) rather than 97% efficient multi-stage scrubber used by the best-performing 3 percent of the semi-regenerative units. EPA should establish the floor based on the section 112 requirements as well as state-of-the-art technology.

Commenter IV-D-59 states that controls for semi-regenerative units are not warranted at all because of low emissions of HAPs (100 lbs/yr per unit) and total pollutants (under 1,000 lbs/yr per unit) and high costs to control emissions under 5 psig. This plant uses an internal scrubber spray system of caustic injection prior to the CRU heat exchanger bundles which they did not identify as control equipment in earlier responses to our information collection requrest. According to the commenter, this type of control is common practice for semi-regenerative units. If EPA does not exclude semi-regenerative units, EPA should determine the MACT floor with respect to HCl emissions as internal caustic spray injection.

Response: As discussed in the preamble to the proposed rule, we subcategorized semi-regenerative and continuous/cyclic CRU based on operational differences in the rejuvenation process (i.e., primarily annual hours the system is regenerating). However, the lack of HCl emissions data available to characterize emissions from semi-regenerative units led EPA to base their MACT floor determination based on current industry control technology practices. Two classes of scrubbers were designated to characterize the general types of scrubbers used to control emissions from CRU catalyst regeneration vents during the coke burn-off step: single stage and multiple stage scrubbers. The single stage system reflects the use of internal scrubbing systems such as caustic spray injection, spray circulating solution, hydroclyclones, and once-through spray scrubbers. Multiple stage scrubbers are generally external to the process (i.e., an add-on control device) and may include packed tower, packed column, plate, spray, and Venturi systems.

A summary of control system data show that 28 percent of continuous CRU use multiple stage scrubbers compared to 6 percent using a single stage scrubber. For cyclic CRU, 36 percent use multiple stage scrubbers compared to 11 percent using single scrubbers. Seventy-two percent of the semi-regenerative units use a single-stage scrubber while only 3 percent use a multiple stage system. Based on these data, EPA determined that the MACT floor for continuous and cyclic CRU is the multiple-stage scrubber while the floor for semi-regenerative units is the single stage scrubber.

Due to the limited data available on the performance of HCl scrubbers for CRU, we characterized the performance of HCl scrubbers based on industry surveys and source test data on HCl scrubbers used in the steel pickling industry. In the preamble to the proposed standard, we discussed the similarities of the HCl emission streams and the basis for the 97% removal efficiency for multiple stage scrubbers and the 92% efficiency for semi-regenerative scrubbers. We selected the 92% efficiency for semi-regenerative processes based on the available data and engineering design considerations of the various types of single stage scrubbers and the efficiency that can be reasonably expected for all semi-regenerative CRU.

The MACT floor for new and existing continuous and cyclic CRU are the same. This is because the catalyst regeneration vent on the top-performing continuous and cyclic CRU apply the same work practices or control devices as the top 12 percent of existing continuous and cyclic CRU. In other words, the floor for existing units is based on the top 12 percent of existing cyclic and continuous CRU and the floor for new units is based on the top-performing units, which are the same in this case.

The MACT floors for new and existing semi-regenerative CRU differ. The MACT floor for existing semi-regenerative units is based on the top 12-percent, which use single-stage scrubbers (including internal caustic spray systems). The concentration limits are included in the rule to allow for the use of these systems. Our data shows that two semi-regenerative CRU use multiple stage scrubbers to control catalyst regeneration coke burn vents. As these are the best-controlled semi-regenerative units, we determined that multiple-stage scrubbers constitute the MACT floor for new semi-regenerative units. Requiring high efficiency HCl scrubbers for existing semi-regenerative units is clearly beyond the MACT floor and would require replacement of existing controls at 72% of the units for nominal additional HAP removal. Therefore, requiring “state-of-the-art” control devices on this intermittent vent at existing units was not included in the final rule.

The EPA refinery information and data regarding HAP emissions from semi-regenerative CRU indicates that these units can be significant sources of HAP emissions during the various regeneration cycles and that air emissions controls and operational practices of one type or another typically are used to reduce these emissions.

2.2 Three Percent O_2 Correction

Comment: Commenter IV-D-26 believes the 3% O_2 correction in the proposed limits for TOC and HCl is inappropriate. According to the commenter, a correction to 3% O_2 is appropriate for boiler applications where O_2 levels are typically less than 6%, but are not appropriate for typical VOC oxidation systems that may operate with 18 to 20% O_2 levels. While the correction would not affect the VOC destruction efficiency, it would drastically affect the absolute default concentrations specified in the limits (i.e., 20 ppmv on a dry basis for TOC, 10 or 30 ppmv on a dry basis for HCl).

Response: The CRU operates under a reducing atmosphere. As such the primary depressurization and purging cycles are expected to have very low if any O_2 (due to safety considerations, i.e., explosions). In addition, the CRU catalyst regeneration is a controlled burn process that operates with very low O_2 concentration (typically less than 3%). Therefore, the 3% O_2 correction in the TOC and HCl ppm limits are not inappropriate because they are needed to account for inordinate amounts of excess air.

2.3 CRU Cutoff for Depressurization and Purging

Comment: Commenters IV-F-3.1, IV-D-37, IV-D-47, IV-D-48, IV-D-49, IV-D-53, IV-D-54, and IV-D-59 recommend changing the proposed cutoff level for control requirements (differential pressure under 1 psig or reactor vent pressure of 1 psig or less) to a reactor vent pressure of under 5 psig. The commenter state that 5 psig is the level used in those States which have the facilities representing the MACT floor (California, Texas, Louisiana). Also, it is unrealistic to measure a differential pressure under 1 psig; 5 psig is the minimum pressure differential that could be determined with any confidence as these vents typically start at pressures around 200 psig. Commenter IV-D-40 says EPA should clarify that control requirements during initial depressuring do not apply after the reactor has been initially depressured to 5 psig.

Response: The EPA agrees with the commenters that since 5 psig is the limit in those States with facilities representing the MACT floor, a limit of 5 psig is appropriate. We have revised the final rule to eliminate the differential pressure limit and change the reactor vent pressure cutoff level from 1 psig to 5 psig. The control requirements apply to depressuring and purging operations until the reactor is depressurized to this level.

2.4 Clarification of TOC Standard

Comment: Commenter IV-D-27 asks EPA to clarify §63.1562(b)(1)(ii) of the proposed rule. If a boiler or process heater is used to control TOC, the vent stream must be introduced into the flame zone or any other location that will achieve the required percent reduction or concentration. Does this mean the stream can be routed to the fuel gas line? If so, this would make a stack test nearly impossible because the fuel gas line feeds all boilers and heaters within a refinery. Also most refineries bring in clean natural gas into the fuel gas line to dilute the H_2S prior to the H_2S monitor to comply with the NSPS. Diluting the gas stream and sending the excess gas to a flare would make it easy to show less than 20 ppm TOC from a boiler.

Response: Section 63.1560(c) of the proposed rule exempts streams routed to a fuel gas system. This exemption remains in the final rule.

2.5 Achievability of HCl Limits Based on Scrubbers in the Steel Pickling Industry

Comment: Commenter IV-F-3.1 points out that the percent reduction standards for HCl emissions during coke burn-off and catalyst regeneration in CRU are based on the performance of scrubbers in the steel pickling industry. According to the commenter, there are technical differences in scrubber characteristics, such as the number of trays and packing depth and it is not clear that the proposed reductions are being achieved by scrubbers for refinery CRU. The industry is in the process of conducting tests to determine if the proposed standards represent the floor and will submit the results.

Response: Scrubber performance for HCl emission control is well-documented. While there are certainly some minor differences in scrubber and vent stream characteristics, these differences have been taken into account in analysis the steel pickling data relative to HCl removal for CRU vent streams. Pertinent summary data are included in the docket and additional test reports supporting the performance level are in the docket for the steel pickling rule. The commenter did not provide additional data or information in support of his assertions; however, at subsequent meetings industry representatives have suggested the sources tested by industry achieved the required HCl reduction. No change was made to the performance requirements for HCl scrubbers relative to the percent reduction standards for HCl emissions during coke burn-off and catalyst regeneration in CRU.

2.6 Evaluate D/F Emissions

Comment: Commenters IV-D-30, IV-D-29, IV-D-31, and IV-D-56 request that EPA evaluate D/F emissions from CRU catalyst regenerator vents. Commenter IV-D-31 ask EPA to include a MACT standard to prevent D/F emissions from CRU catalyst regeneration vents. Commenter IV-D-29 points out that the emissions from CRU include organic hydrocarbons, chlorinated compounds, and inorganic chlorides. At the temperature range of 482°F to 842°F, the inorganic chlorides from the coke burn-off process can easily form D/F. At the 20 ppmv outlet concentration, the concentration of D/F may expose humans to a level higher than the EPA's dose limit of 0.006 picograms per kilogram per day or the maximum tolerable dose of 1 picogram per kilogram per day proposed by the Agency for Toxic Substances and Disease Registry. These limits still can be exceeded even if the 98% emission reduction standard is achieved. Since combustion of vent emissions at 1,400°F provides direct control of D/F, this requirement should be added to the standard with associated monitoring and recordkeeping requirements. Commenter IV-D-30 asks that EPA note the presence of D/F in the CRU and CCU emission streams and the extent to which the proposed standards control them. Data collection in conjunction with CARB on D/F emissions should be extended to cover emissions from CRU in their various cycles (chloriding cycle, sulfiding step, and purge cycle).

Response: The EPA acknowledges the presence of D/F emissions in the CRU catalyst regeneration vent stream and the EPA's refinery database contains relevant information and data on these emissions. We have also worked closely with Regional, State, and local agencies to collect additional information on D/F emissions throughout the course of this rule making; and those efforts are continuing. For example, we collaborated with CARB on source testing of CRU vent streams to test directly for D/F during coke burn. Based on the temperature and compositional characteristics of the purge cycle venting, D/F emissions during/from this cycle are not expected.

The EPA did not establish a specific emission standard for D/F in this rule. Although, it should be noted that the MACT floor technology determined for CRU inorganic emissions, wet scrubbers, also is anticipated to effect some control of D/F emissions.

A preliminary risk assessment was performed for the CRU vent based on the D/F emissions measured during the CARB source test. No significant risks were found that justified implementing controls beyond the floor. However if, after collection of additional information, it is later determined that the D/F emissions pose an unacceptable risk we will regulate the CRU catalyst regeneration stream under the risk standards.

The presences (or absence) of D/F emissions from the CCU vent are discussed in comment/response 1.15.

2.7 Format of Proposed Standard for Organic HAP

Comment: Commenter IV-D-25 urges EPA to adopt an output-based format using throughput to replace or supplement the proposed standard, pointing to the NO_x rule for new utility boilers as a precedent. This rule ties the emission limit to the quantity of electricity produced rather than the quantity of fuel burned. According to the commenter, this revised format would allow facilities to address emissions from a broader viewpoint, encourage redesign of the process to achieve the emissions limit, and allow comparisons among different types of control equipment.

Response: A throughput format is not feasible or meaningful for the CRU because the equipment standard required for control of organics is based on conventional combustion technology (i.e., venting emissions to a flare or combustion device). Since semi-regenerative and cyclic units must shutdown to regenerate and the period of operation between regeneration cycles is dependent on a variety of parameters not just unit throughput, a throughput format would not be appropriate in this case.

2.8 New Combustion Technologies

Comment: Commenter IV-D-25 suggests EPA change the wording in the proposed rule from "a flare that meets the requirements for control devices in..." to "a control device that meets the requirements in..." It is possible that in certain applications or as new technologies are introduced that other options will be available to control emissions.

Response: We agree with the commenter's suggestion and revised the proposed rule to refer to "use of a control device that meets the requirements in 40 CFR 63.11." If a facility uses a combustion technology other than flares that achieves 98% destruction efficiency, they can request approval of an alternative standard along with performance test, monitoring, and recordkeeping/reporting requirements.

2.9 Opacity Limit for Flares

Comment: Commenters IV-D-27, IV-D-31, and IV-D-56 urges EPA to include an opacity limit for flares that combust TOC streams as an indicator of good combustion.

Response: We did not include an opacity limit for flares directly in the CRU standards because the rule requires flares used to comply with the rule meet the design and operating requirements in 40 CFR 63.11 of the NESHAP General Provisions, which in turn requires flares to operate with no visible emissions.

2.10 Requirements for Final Purge Vent

Comment: Commenter IV-D-40 asks EPA to clarify requirements applicable to vent emissions from the final purge cycle. Guidance is needed as to when the regeneration cycle has moved from the catalyst rejuvenation phase to the final purge. Many operators have different criteria for when they go back to the flare. The commenter suggests that the final purge be defined as commencing when hydrogen is readmitted to the reactor (which would denote when control equipment would again apply to the vent).

Response: The catalyst rejuvenation phase is characterized by pressurizing the system with air (excess O_2) to evenly redistribute the metal catalyst on the catalyst particles. Subsequent depressurization and system purges, typically a nitrogen purge followed by a hydrogen purge, are considered purge cycles that require appropriate control.

2.11 Alternative Standard for Inorganic HAP Emissions

Comment: Commenter IV-D-54 believes some CRU can demonstrate by material balance that only a few pounds of HCl are emitted each day. These units should not be subject to the same control requirements as units with higher emissions. EPA should add an alterative standard which limits annual mass emissions of HCl using the same rationale as for the alternative Ni standard (lbs/hr). This commenter suggests a limit of one to two tpy of HCl.

Response: Available data show scrubbers are a well-established control technology for HCl emissions from CRU catalyst regeneration vents. Although we agree that HCl emissions from continuous CRU are generally lower in terms of mass per unit time over the short term, the annual emissions from these units appear to be as high or higher than cyclic or semi-regenerative units due to differences in operating hours. Consequently, a lb/hr limit becomes problematic both to evaluate (i.e., data are not available to establish a separate, mass cut-off applicable to the different types of CRU regenerator units) and to enforce (i.e., inaccuracies in the mass balance approach causes problems). Furthermore, during site visits to 10 refineries, none of the operators believed that they could perform an accurate inventory on either the chloriding agent or the caustic consumption (for scrubbers) to assess HCl emissions or emission reductions using a material balance.

As discussed in the preamble to the proposed rule, we subcategorized semi-regenerative and continuous/cyclic CRU based on operational differences in the regeneration process (i.e., primarily annual hours the system is regenerating). However, the lack of HCl emissions data available to characterize emissions from these units led EPA to base their MACT floor determination on current industry control technology practices. Two classes of scrubbers were designated to characterize the general types of scrubbers used to control emissions from CRU catalyst regeneration vents during the coke burn-off step: single state and multiple stage scrubbers. The performance of HCl scrubber systems is best characterized by removal efficiency or a concentration limit when inlet concentrations are low. The proposed rule provided concentration limits as an alternative to removal efficiency requirements. The concentration limits were established to provide operational flexibility to owner and operators of affected CRU with low HCl exhaust concentrations (low HCl emissions). Based upon these considerations, EPA does not consider the suggested regulatory alternative to be either necessary or appropriate.

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3.0 CONTROL REQUIREMENTS FOR SRU

3.1 NSPS as MACT Floor

Comment: Since substantive data were not available, EPA selected the NSPS limit as the MACT floor for SRU. Commenter IV-D-26 believes EPA should instead collect data to determine the actual emissions level of the top performing units to establish limits based on proven performance reflecting current control technology. Historically, units subject to the NSPS operate with emissions lower than the required limits. Thus, the actual level of performance of the top performing units is probably lower than the proposed rule. Commenter IV-D-56 believes that selection of the NSPS as the MACT floor does not comply with section 112(d) or Congressional intent in establishing MACT floors. Specifically, as established the MACT floor: (1) must be at least as stringent if not more stringent than BACT, (2) does not consider sulfur pretreatment via catalytic hydrotreatment, (3) does not require backup units and/or parallel trains, (4) does not require continuous monitoring systems required by the NSPS, (5) relied on limited data from only one refinery to establish the floor, and (6) will not reduce the elevated levels of SO_2 resulting from upset conditions and associated health threats to surrounding communities. According to the commenter, the EPA must collect more data on COS and CS_2 (and H_2S) from refineries and make the data publicly available for review.

Response: As previously discussed in comment/responses 1.2 and 1.3, in determining MACT, the EPA can consider alternative approaches for establishing the MACT floor. These include: (1) source test data that characterize actual emissions discharged by the sources, (2) use of a technology and an accompanying demonstrated achievable emission level that characterizes the technology and accounts for process and air pollution control device variability, and (3) information on Federal and State regulations and/or permit conditions that apply to the source. If the information gathered indicates that more than 12% of the existing units or sources are currently subject to the NSPS for that source category and no more stringent rules apply, the NSPS thus represents the average emission limitation achieved, in terms of a regulatory requirement, by the best performing 12% of existing sources.

We agree that most SRU will operate a lower emission level over the long term in order to comply with the short term not to be exceeded standard of the NSPS. This issue also had been discussed previously in comment/response 1.11. The selection of an operating limit for unit emissions is to a large extent dependent on the averaging time used to characterize the emissions or unit operation. In general, emission limits formatted in the short term, not to be exceeded values must take into account variations in the process operations and the test methods used to measure emissions.

With regard to the commenters recommendation to require back-up units and/or parallel sulfur recovery unit trains to limit SO_2 emissions resulting from upset and unit shutdowns, EPA does not have the authority under section 112 to regulate criteria pollutants such as SO_2. It should also be pointed out that hydrotreatment would not reduce the emissions from the SRU. Hydrotreatment reduces or removes the sulfur from refinery streams up-stream of the SRU and the removed sulfur (typically in the form of H_2S) is sent to the SRU for sulfur recovery.

With regard to the comment that EPA established the MACT floor based on limited data from one refinery, this comment is baseless and blatantly false as the establishment of the MACT floor was based on data collected from a nationwide survey of SRU.

3.2 Parallel Unit Configurations as MACT Floor or NSPS

Comment: Commenters IV-D-31, IV-D-35, IV-D-46, and IV-D-56 urge EPA to include requirements for multiple, parallel SRU to ensure that backup units to prevent flaring of unscrubbed, raw refinery fuel gases should any units fail. According to commenter IV-D-31, many refineries use multiple parallel units to ensure continuous removal of sulfur even when one of the SRU is not operating. EPA should determine whether this configuration is in place in at least 12% of the existing refineries and, if so, require this technology to ensure emission reductions that meet MACT requirements. Commenter IV-D-35 recommends that EPA include this approach in the NSPS to allow for full spare capacity of SRU, as currently practiced in California. Rule 66 from the Los Angeles Air Pollution Control District requires full sparing and backup of SRU. Complete spare plants allow for full compliance even during shutdowns and upset conditions.

Commenter IV-D-56 states that more than 12% of the sour crude processing refineries in Texas, the nation's largest oil refining State are required by permit to operate SRU with backup units and/or parallel trains. The commenters maintain that EPA must require as MACT for sulfur removal 100% backup SRU in parallel trains or multiple trains especially since SRU experience significant downtime and operating problems. In support, the commenter describes serious upset and maintenance problems at a number of local refineries, and for one refinery in particular, the high number of NSPS violations resulting from an undersized and poorly designed SRU and use of off-spec refinery fuel gas, the 2,000 tons or more of excess SO_2 emissions from malfunctions, NAAQS exceedances of primary and secondary standard, and repeated citizen complaints.

Response: As noted in the previous response, we do not have the statutory authority to regulate criteria pollutants such as SO_2 or to revise the NSPS under section 111 to require backup units/parallel trains for improved control of SO_2. However, we do have the statutory authority to require plants to take the proper steps needed to minimize HAP emissions resulting from startups, shutdowns, and malfunctions. We will expect the SSMP submitted as part of the notification of compliance status to address the situations that result from the conditions described by the commenter. The rule requires combustion of sulfur plant gases to destroy the sulfur HAP compounds (COS and CS_2) to less than 300 ppmv. Therefore, the rule requires HAP control when there are SRU upsets. We also are requiring plants to account for releases through by-pass lines. However, EPA cannot address the need for a back-up SRU requirement under this MACT rulemaking; this would be an issue covered in the State Implementation Plan relating to criteria pollutant emissions.

3.3 Off-site Sulfur Plants

Commenters IV-D-47, IV-D-48, and IV-D-53 ask EPA to exempt sulfur plants are not part of a refinery but which receive gases to provide redundant emergency or maintenance backup for a refinery sulfur plant. If this change is not made, these third-party plants are likely to terminate their agreements with adjacent refineries instead of spending the money to install controls for a plant that receives flow a couple of times a year during emergencies, maintenance, or upsets. This would result in the refinery having to flare the gases and would increase emissions of sulfur.

Response: We do not have, and the commenter did not provide, specific data to know the volume of sulfur containing gases (or the resulting emissions) sent to off-site facilities for redundant emergency or maintenance backup. The NSPS states that a sulfur recovery plant need not be onsite to be subject to the rule. However, under section 112, the definition of major source refers to any stationary source or group of stationary sources located within a contiguous area and under common control that emits a specified level of HAPs individually (10 tpy or more) or collectively (25 tpy or more). We are not certain that the off-site facility clearly meets the criteria for "contiguous area" and that the lease agreement denotes "under common control." Based on the information presented, we do not believe that gases received by a third party plant solely for redundant emergency or maintenance backup would meet the HAP threshold levels for major source status. For these reasons, we excluded off-site sulfur recovery plants receiving gases solely for redundant emergency or maintenance backup as an affected source under the rule. These plants may be subject to NSPS requirements, however.

3.4 Hydrotreatment as MACT Floor

Comment: Commenter IV-D-56 states that EPA failed to consider sulfur pretreatment before the SRU as an acceptable technology for reducing the sulfur feed to the unit and controlling SO_2 emissions to below the 300 ppmv limit in the NSPS. Several refineries (Texas and California) use catalytic hydrotreatment units or hydrotreaters in addition to SRU technology which can effectively reduce emissions from the SRU/tail gas incinerator below the NSPS level. Catalytic hydrotreatment must be required at all new and existing SRU units since it is in place at more than 12% of all existing refineries in the US. EPA should conduct a review at all existing refineries and add this to the final standard. MACT needs to require 100% backup systems whether it be 100 percent by backup SRU or a combination of backup catalytic hydrotreatment and suitable-sized SRU.

Response: The commenter did not provide any data to support the contention that hydrotreatment reduces SO_2 emissions from SRU. Based on the information at hand, hydrotreatment would not reduce the emissions from the SRU but rather, it is anticipated to increase the sulfur load to the sulfur recovery plant. Hydrotreatment reduces or removes the sulfur from refinery streams up-stream of the SRU and the removed sulfur (typically in the form of H_2S) is sent to the SRU for sulfur recovery. The EPA is examining hydrotreatment as a part of the efforts to reduce emissions of HAP metals and in coordination of the MACT standard with the Tier 2 fuel standards. We are aware of the wide spread use of hydrotreatment in the refining industry but are not requiring its use as a part of the HAP control scheme for refinery CCU and SRU vents for a number of reasons which have been discussed previously (see comment/response 1.19). We anticipate refineries to expand hydrotreatment capacity in complying with the Tier 2 fuel standards, but we also anticipate that this will increase current SRU sulfur loads and cause many refineries to expand or build new SRU.

3.5 Thermal Oxidizers for NSPS SRU

Comment: Commenter IV-D-28 believes the proposed MACT standard for TRS emissions from SRU is appropriately more stringent than the NSPS where it requires a thermal oxidizer following the tail gas unit, consistent with best industry practices. This control technique should apply to all SRU. The commenter recommends that the MACT standard be applied to NSPS units. He suggests a 3-5 year phase in period to correspond with refinery turnaround periods. Commenter IV-D-46 interprets the preamble (63 FR 48896) to claim that tail gas treatment at SRU is equivalent to a fume incinerator in the level of control. The commenters does not accept this statement because COS and CS_2 emissions will be higher from tail gas units that do not have a fume incinerator in-line before discharge.

Response: The MACT standard for SRU is based on the NSPS in 40 CFR Part 60 and should be considered equivalent in stringency. The concentration standard is used to allow owner or operators a greater degree of flexibility that would be permitted if an equipment standard (i.e., incinerator) was used. The concentration standard reflects a high efficiency SRU. Some tail gas treatment units get high recoveries and thus there is no need for incineration of the off-gas. Incineration would be required for those units with a low recovery efficiency.

3.6 Consistent Definition of TRS

Comment: Commenter IV-D-25 believes EPA should use a definition of TRS consistent with the NSPS for Kraft Paper Mills (H_2S, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide) and/or the NSPS for Petroleum Refineries (H_2S, COS, and CS_2). Commenter IV-D-54 requests that EPA eliminate TRS as a surrogate for sulfur HAP. The major component of TRS is likely to be H_2S and most if not all variances in TRS will be the result of H_2S variance. This should not be a violation since HAP emissions (COS and CS_2) will not necessarily change. The EPA should establish the limit using only COS and CS_2.

Response: We agree that it would be more effective to have a single definition of TRS in all rules. However, in this particular situation, we have decided not to use the cited NSPS definitions because they include compounds that are not listed HAP, e.g., H_2S, which is not a listed HAP. With regard to the commenter who states that the TRS limit should be based solely on COS and CS_2 because exceedance of the limit is more likely the result of H_2S increases, no data were provide to substantiate this claim and this does not appear to be the case base on the limited information available to the Agency. In the NSPS, there is a 10 ppmv limit on H_2S emissions in addition to the 300 ppmv TRS limit. Therefore, the 300 ppmv limit must pertain predominantly to COS and CS_2. We did account for the H_2S increment in the NSPS limit in establishing the MACT standard and the did not include H_2S in the definition of reduced sulfur HAP compounds.

3.7 Format of Proposed Standard

Comment: Commenter IV-D-25 urges EPA to adopt an output-based format for the final TRS standards to replace or supplement the proposed standard, pointing to the NO_x rule for new utility boilers as a precedent. This rule ties the emission limit to the quantity of electricity produced rather than the quantity of fuel burned. According to the commenter, this revised format would allow facilities to address emissions from a broader viewpoint, encourage redesign of the process to achieve the emissions limit, and allow comparisons among different types of control equipment.

Response: We did not change the reduced sulfur HAP standard to incorporate an output based format because, in this case, the revised format would require an additional conversion step. We are not aware of any advantages that would result from this additional complication; there are, however, some disadvantages. The additional conversion step would create opportunities for potential errors and the revised format would conflict with the NSPS.

3.8 Incinerator for TRS Control

Comment: Commenter IV-D-27 does not believe that incineration is adequate for TRS control because complete oxidation may not occur. She points to one refinery in her State that frequently runs the SRU stack with less than 1% O_2.

Response: In response to the commenter's concerns, we added requirements for a continuous O_2 monitor to the TRS requirements. These requirements are the same as those in the NSPS for this source category.

3.9 Calculation of TRS Limit

Comment: Commenter IV-D-35 believes it is inaccurate to deduct the 10 ppm from the 300 ppm TRS limit and assume the remainder is 290 ppm COS. The commenter explains that Beavon-Stretford sulfur plants operate without incineration of the tail gas, thus eliminating the additional CO_2 and CO emissions common with amine scrubbing of the tail gas sulfur. The amount of COS in the hydrogenated tail gas is determined by the equilibrium of the following reaction: CO_2 + H_2S <=====> COS + H_2O. The equilibrium concentration level of COS is normally 50-60 ppmv. If COS levels are over the chemical equilibrium level of about 60 ppm of COS, it is due in part to low partial pressure of H_2. Normally, the COS is not considered a HAP at this level and it seldom is close to 300 ppmv.

Response: In response to the commenter's concerns, it is important to note that as the NSPS defines TRS to include COS plus CS_2 plus H_2S concentrations. The NSPS H_2S limit is 10 ppmv; therefore it is reasonable to conclude that the COS and CS_2 portion of the 300 ppmv limit is between 290 and 300 ppmv depending on the H_2S concentration. Also it should be pointed out that the HAP designation is not contingent upon the compound being present at a particular concentration; COS is a HAP at any concentration.

3.10 Sulfur Recovery Pits, Stretford Solution Tanks, and Non-Claus SRU

Comment: Commenters IV-D-38 and IV-D-56 urges EPA to include a MACT standard for sulfur recovery pits, Stretford Solution Tanks, and nonClaus SRU in the final rule. EPA is not meeting the requirements of the CAA if the final rule does not address these emissions which are documented in the BID for the proposed standards.

Commenters IV-D-39, IV-D-47, IV-D-53, and IV-D-54 disagree. Commenter IV-D-53 states that emissions from sulfur pits can 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 purge the pits to prevent the buildup of gases; emissions are controlled by combining the purged gases with the SRU or tail gas treatment off-gas and venting to an incinerator. Although data are not available to accurately assess HAP emissions, the commenter believes H_2S, COS, and CS_2 emissions are much lower than the TRS standard of 300 ppmv. The commenters believe the emissions should be considered *de minimus*.

Certain types of tail gas treatment units such as Stretford units use a series of open vessels as part of the solution circulation loop and a direct air contact cooling tower to cool the solution. Emission data are not available to accurately assess HAP emissions from these units. Based on process considerations there are no significant H_2S, COS, or CS_2 emissions under normal operation according to Commenter IV-D-53. Commenter IV-D-39 explains that his company does not vent vapors from Stretford tanks or Stretford solution cooling towers because there is little opportunity for the formation of COS or CS_2 in the process which reduces all sulfur species to H_2S. Controls would be infeasible because the tanks are large and use a large quantity of air in the oxidation step. The air also bears the elemental sulfur formed at the top of the tank. If the tanks were covered and sufficient freeboard could be added, it is unclear what technology might be used to control the low level of COS and CS_2 in the stream. Similar problems pertain to the enclosure of the direct-contact cooling tower.

Commenters IV-D-39, IV-D-53, and IV-D-54 believe emissions are expected to be lower than the proposed standard for SRU and should be considered *de minimus*.

Response: In the preamble to the proposed rule, we requested that commenters submit specific data and information regarding the extent and type of emissions from these sources. Commenters submitted no data to characterize quantity of emissions from these units. We can make no determination at this time without specific data. We will collect additional information and data needed to assess these and other potential sources in conjunction with the development of residual risks standards.

3.11 NSPS Exemption for Small SRU

Comment: Commenter IV-G-2 believes the final standard should include the NSPS exemption for SRU with capacities less than 20 long tons of sulfur per day. According to the commenter, State and local regulations include adequate control requirements. In support, the commenter cites the Agency's rationale for the exclusion in 1978 as to lessen the economic impact on small refineries and encourage installation of sulfur plants at small refineries. The cost for a small unit to meet the sulfur standard is at least $2 million according to the commenter for a very small incremental increase in control.

Response: We did not include the exemption for small SRU because MACT standards under section 112 are technology-based rather than cost-based. The NSPS cut-off established in 1978 was based on a cost-effectiveness analysis. Technology for the control of emissions from these source is well-demonstrated and our economic analysis does not indicate any economic impact on the industry as a result of controlling these units.

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4.0 CONTROL REQUIREMENTS FOR BY-PASS LINES

4.1 Flow Meter Alternatives for CCU Regenerator By-Pass Lines

Comment: Commenters IV-D-37, IV-D-40, IV-D-47, IV-D-48, and IV-D-53 recommend revising the proposed requirements for by-pass lines to allow other alternatives. According to the commenters, the flow meter option does not work for the type of by-pass lines used for most CCU regenerators. Flow monitors are difficult to maintain and operate for a stack that can suddenly receive large flows of gas in the event of a by-pass. For some refineries, car-sealing closed the by-pass valve is not an option because the valve must be kept open in the event an emergency bypass is required.

The commenters suggest a water seal pot that has sufficient head pressure in the drum to prevent flow through the by-pass stack with monitoring of the liquid level of the water seal. This provides a continuous measure of where gas is being diverted, so there is no need for an hourly visual inspection. They also suggest electronic bypass valve position monitoring (which provides continuous documentation of the valve position such that hourly inspections would not be needed), a flow indicator or a level indicator (or other alternative device that determines at least hourly whether a vent stream is present in the by-pass line) or a blind flange. A blind flange can assure a no-flow condition as does the chain-locked or car-sealed valve. As with a closed valve, a monthly visual inspection could be required. Suggested language for §63.1565(h)(1) of the rule is included in their comments to be more consistent with the MACT I rule.

Response: We agree that the requirements for a by-pass line can be more flexible to accommodate different types of systems that provide the same information as a flow indicator. The purpose of the monitoring is to ensure that each by-pass event is recorded and reported to EPA. This can be done just as well using electronic by-pass valve position monitoring that provides a continuous record of the valve position, or by a flow indicator or level indicator that determines on an hourly basis whether or not vent stream flow is present. If a continuous record of the valve position for each hour is done by a recording system, hourly visual inspections would not be needed. If a continuous recorder is not used, you would need to make visual inspections every hour and record whether a vent stream is present. A blind flange also can be used to assure a no-flow condition as suggested by the commenter as long as it is bolted in place. Plants that want to use a system other than a flow indicator, level recorder, electronic valve position monitor must request the use of an alternative control system and provide documentation supporting their equivalency to the rule requirements.

4.2 Installation Requirement for Flow Meter

Comment: Commenters IV-D-37, IV-D-47, and IV-D-53 request that EPA revise the proposed requirements for by-pass lines by deleting the provision for installation of a flow monitor at the entrance to any by-pass line that could divert the vent stream from the control device to the atmosphere or revise the language to allow installation at or as near as practical to the entrance to any by-pass line. The requirement for installation at the entrance of the by-pass line needlessly restricts the location of the device but also in effect requires that the device be a flow indicator. Site specific piping configurations may preclude installation at the entrance, but this does not impair the ability to determine whether or not flow is present in the line.

Response: The EPA agrees with the comment and has revised the final rule accordingly. It was not our intention to needlessly restrict the type of monitoring device used (if equivalent) or the location of the device as long as the owner or operator maintains the ability to determine whether or not flow is present in the line.

4.3 Continuous Monitoring Option for CCU By-Pass Valves

Comment: Commenter IV-D-40 asks EPA to include in the final rule an option for the use of continuous monitoring of both the CO boiler stack and the by-pass stack to verify that the combined emissions do not exceed the organic and inorganic HAP standards for CCU. The commenter requests an alternative because the size of the by-pass line and location/design of the by-pass valve make it difficult to achieve a zero percent leakage rate even with redesign or replacement, resulting in a small flow during normal operations when the valve is in a closed position.

Response: To further understand the comments regarding compliance with the by-pass requirements, we discussed the issue with the commenter on a number of occasions. The commenter's original concern related to the technical issue that the CCU unit regenerator vent configuration would cause problems in demonstrating compliance with the by-pass provisions of the rule. After discussions with the facility staff regarding the by-pass requirements of the final rule and further analysis by the facility, it was concluded that the facility can comply with the requirements of the final rule by use of conventional gas flow technologies that can be incorporated into the current configuration.

5.0 MONITORING REQUIREMENTS

5.1 CO Boiler Monitoring Requirements for Full-Burn FCCU

Comment: Twelve industry commenters (IV-F-3.1, IV-F-3.2, IV-D-39, IV-D-43, IV-D-44, IV-D-47, IV-D-48, IV-D-49, IV-D-51, IV-D-53, IV-D-54, IV-D-59) recommend that the final standard include consistent monitoring requirements for full-burn and partial-burn CCU or eliminate them. Commenters IV-D-51 and IV-D-53 believe their nonNSPS units will not be able to meet the 1-hour averaging time without high costs and/or production capacity losses because the units are not specifically designed for this level of performance. According to the commenters, CCU that use complete combustion (full-burn) should have no monitoring or monitoring based on 24-hour averages rather than 1-hour averages as required in the NSPS. In full-burn units, the coke deposited on the catalyst is completely combusted within the regenerator at high temperature (over 1,300°F). In partial-burn units, coke is partially combusted within the regenerator which operates at lower temperatures and the flue gas is burned in a separate boiler commonly called a CO boiler. The proposed monitoring requirements exempt partial-burn CCU that vent emissions to a CO boiler above 44 MW based on the robustness of these boilers to manage fluctuations in inlet flue gas CO content. Daily averages apply to a CCU with emissions vented to combustion devices other than furnaces or boilers. However, a full-burn CCU must monitor using a 1-hour averaging period. Because emissions from full-burn and partial-burn CCU are comparable, full-burn units are as "robust" as the partial burn units, and operators need more time than 1-hour to make changes if need, EPA should exempt full-burn units from monitoring requirements like partial-burn units or allow the 24-hour averaging. Commenter IV-D-54 states that EPA has provided no data to support a contention that there is a difference in organic HAP emissions from partial and full-combustion units or any theoretical basis to believe that combustion is less robust in control performance. Thus, there is no technical basis to require more frequent monitoring. Several of the commenters contend the cost of complying is very high and has not been included in the cost analysis.

Commenters IV-D-30 and IV-D-31 acknowledges that 1-hour averaging period for a 500 ppmv limit may create compliance problems for many units with complete combustion. While changes in feed do induce some operational instability which takes some time to correct, good operating practices, use of combustion promoters, more combustion air, better distribution of combustion air, and minimizing feed changes are options that can be tried to control this problem. If the problem persists, EPA could reformat the standard using an 8-hour average with a statistical approach to accommodate the variability of CO emissions. Units could be required to simultaneous ensure that the 90th percentile CO concentration as measured by a CEMS is under 500 ppmv and the 99th percentile is below 1,000 ppmv. Such a standard would ensure control of organic pollutants while allowing for occasional excursions due to changes in operating conditions.

Response: The EPA acknowledges the commenters concerns regarding monitoring requirements for full-burn CCU. However, the commenters did not provide adequate historical data to support their contention. It also appears contradictory that a "robust" system cannot meet the 1-hour limit. The CO boilers or other furnaces and boilers employ auxiliary fuel and air to promote and maintain combustion; differentiating between these processes is technically defensible. Furthermore, based on available data from States and regions, we maintain the position that CO emissions (i.e., the ability to maintain and control complete combustion) is not a multiple hour control variable as suggested.

Under the structure of the final rule, a FCCU without an add-on control device, a combustion device in this case, would be required to install and operate a CEMS to monitor the CO emissions directly for compliance with the 1-hour standard of 500 ppmv. The 500 ppmv 1-hr average value was set in the 1973 NSPS specifically to accommodate complete burn units. (See Background Information For Proposed New Source Performance Standards, Volume 1, MAIN TEXT, APD-1352a, Technical Report No. 7.) Without any data that shows otherwise, it has been concluded that existing nonNSPS units should be subject to the same standard, i.e., the 500 ppmv 1-hr average rather than a higher standard that would result from incorporating a longer averaging time. The EPA went to the States to obtain data on partial burn units and the limited data we received did not support a longer averaging time for these units. The data previously on hand supported a 1-hour limit for these units. Other commenters stated that the 500 limit was too high; which generally agrees with the NSPS analysis that showed a value of about 25 ppmv as appropriate for partial burn units with a CO boiler.

Another factor that would have to be considered if the Agency were to consider a change in the averaging time of the standard is that the NSPS limit of 500 ppm on a 1-hour basis takes into consideration fluctuations in CO concentration resulting from process operation and test method variability, as discussed previously in comment/response 1.11. Changing the averaging time would also require a change in the numerical emission limit to correspond to the increase averaging time. We do not have the historical data to make this determination at this time. The 500 ppmv limit is based on a short-term averaging time of 1-hour and is set at this value high to account for process fluctuations and source test variability. That is, given a 500 ppmv limit evaluated on a 1-hour basis, refiners are forced to operate at much lower CO levels (e.g., 50 - 100 ppmv) to comply with the standard during process fluctuations. If the limit were based on a longer-term average, a lower limit could be selected that would be much closer to actual operating levels over the long term. However, commenters did not provide the data needed to analyze the alternative CO or averaging time limits for existing non-NSPS full-burn units. For these reasons, we did not revise the limit or the averaging time.

Regarding the difference in total organic HAP emissions from complete versus partial combustion units, the EPA concluded that complete combustion units had similar total organic HAP emissions as partial combustion units that are followed by a

CO boiler. However, all of the organic HAP data used in that analysis were for full-burn or complete combustion units with CO levels below 500 ppmv.

5.2 Process Data and Secondary Measurement Devices As Alternatives to Flow Monitoring Requirements for Wet Scrubbers

Comment: Commenters IV-D-37, IV-D-47, IV-D-49, IV-D-53, and IV-D-59 request alternative monitoring requirements for wet scrubbers. Commenter IV-D-49 opposes monitoring flow to the unit where a wet scrubber is used to comply with the standards for the CCU catalyst regenerator vent because of difficulties posed by the heavy coke burn. Others oppose the proposed monitoring requirements for wet scrubbers (pressure drop across the scrubber, gas flow rate, and total water or scrubbing liquid flow rate to the scrubber) because these direct measurement method poses technical difficulties due to the erosive and corrosive nature of the hot gases and liquids. Consequently, direct flow measurement devices are costly and problematic to install and maintain. These devices also require unit downtime for installation. According to the commenters, few facilities with wet scrubbers for CCU directly measure gas flow or scrubber liquid flow rate. Gas flow rate is a problem because the ducting is very large and tends to be irregularly shaped with extreme conditions of heat and particulates all of which affect instrument reliability. Instead, the gas flow rate is determined based on process data such as the O_2 and CO content of the regenerator outlet flue gas. Liquid flow rate is determined based on such parameters as the liquid pressure at the inlet to the scrubber and the wet gas scrubber liquid purge flow rate. These methods for gas and liquid flow rates have been accepted by Louisiana, Texas, and New Jersey and provide a very good correlation with actual measured flow rate data. The commenters recommend that the rule clearly allow the use of other secondary measurement devices and calculation procedures for this purpose. They suggest revising the rule to require a measurement device equipped with a continuous recorder to measure and record the average daily pressure drop across the scrubber, the average daily gas flow rate to or through the scrubber, and the average daily total water (or scrubbing liquid) flow rate to the scrubber. As an alternative to direct measurement devices, these parameters can be determined using process data and/or other secondary measurement devices. Commenter IV-D-59 asks EPA to adopt either pressure drop across the scrubber or scrubber liquid flow rate and gas flow rate as the monitoring requirements but not both.

Response: In the "top-down" approach used by EPA, we first look at methods for the direct measurement of emissions and if this is not technically or economically feasible, we look at direct measurement of operating parameters. The calculation method suggested by the commenter is the least preferred monitoring method because it may not show when the control device is not operating at the design level necessary to continuous comply with the standards. However, direct volumetric gas flow rate monitoring is problematic for typical CCU because of the size and configuration of the duct vent. In this case (i.e., for CCU gas flow rate), volumetric gas flow rate as determined by process control monitors for air blast rate (as used in the NSPS) combined with gas stream temperature provide a more reliable and equally accurate measure of the parameter. Therefore, this type of monitoring is allowed in the rule under certain provisions.

Without specific information and data on the secondary measurement devices and calculation procedures, we can not assess the validity of the commenter's assertions regarding direct measurement of liquid flow rates for wet scrubbers and whether the recommended approach would provided consistent and equivalent results when compared to direct measurement techniques. We believe the commenters will need to request approval of an alternative monitoring method from the Administrator in this case rather than State and local permitting authorities as a major monitoring change. A major change to monitoring is a modification to federally-required monitoring that uses unproven technology or procedures or is an entirely new method (sometimes necessary when the required monitoring is unsuitable). Such a change may be site-specific or may apply to one or more source categories and will usually set a national precedent. One example is a new monitoring approach developed to apply to a control technology not contemplated in the applicable regulation. Procedures for requesting an alternative monitoring method are described in §63.8(f) of the NESHAP General Provisions.

5.3 Monitoring Requirements for Other Wet Scrubber Designs

Comment: Commenter IV-D-37 states that the proposed monitoring requirements are not appropriate for jet ejector wet scrubbers. In these units, the liquid (not the gas) is injected/atomized via nozzles, or jet ejectors, into the flue gas. Consequently, the pressure drop of the flue gas is not an appropriate operating parameter for monitoring. The pressure drop of the scrubbing liquid across the nozzles is relevant, but that is a function of the pump pressure or the liquid flow rate which the proposed rule already requires to be monitored. The commenter suggests that the rule state that wet scrubbers of the jet-ejector design for CCU are not required to monitor pressure drop.

Response: Pressure drop is an appropriate monitoring parameter for any Venturi-type scrubber. Venturi wet scrubbers typically inject water (or other scrubbing liquid) near the Venturi throat, which atomizes, collides with the particulate matter, and thus improves scrubbing performance. We agree with the commenter that pressure drop of the flue gas is not an appropriate operating parameter for monitoring jet ejector wet scrubbers that do not use a Venturi design for PM removal. In response, we have revised the proposed rule to not require pressure drop monitoring for nonVenturi, jet ejector type of wet scrubbers for CCU. However, the owner or operator must still monitor the gas flow rate to the scrubber and the total scrubbing liquid flow rate to the scrubber as indicators of proper operation and overall performance.

5.4 Continuous O_2 Monitor for Full Burn CCU Regenerators

Comment: Commenters IV-D-49 and IV-D-59 opposes the alternative monitoring provisions for the use of a continuous O_2 monitor for full burn CCU regenerators. Like flow monitors, these are difficult to design and maintain due to the concentration of particulates in the stream. The commenter recommends allowing the placement of the monitor downstream of the particulate control device or the use of alternate periodic monitoring once per day rather than on a continuous basis.

Response: The O_2 monitor is needed to assess full burn operation of the unit and have been in use by NSPS units for over 25 years. While we do not believe that monitoring this parameter once per day would provide the information necessary to ensure continuous compliance, we do not oppose alternative placement of the monitor downstream, of the particulate control device provided no air is introduced that would corrupt measurements.

5.5 Monitoring of Uncontrolled CCU

Comment: Commenters IV-F-3.1, IV-D-47, IV-D-48, IV-D-49, IV-D-53, and IV-D-59 urge EPA to include specific provisions for the monitoring of uncontrolled CCU rather than requiring the permitting authority to establish requirements. They recommend monitoring the coke burn rate based on a compliance test or engineering analysis due to the strong correlation of cyclone performance (and therefore PM emissions) with coke burn (i.e., exhaust gas flow rate). The commenters suggest monitoring the daily average coke burn rate for CCU that will meet the PM limit without an ESP or scrubber. For CCU that will meet the Ni standard without an ESP or scrubber, the monthly average E-Cat Ni concentration should also be a monitored parameter. This concentration can be used along with a correlation between coke burn rate and PM emissions to demonstrate compliance with the Ni standard.

Commenter IV-D-54 opposes calculating and recording the coke burn rate if the source is electing to comply with the alternative Ni limit, where it is irrelevant. He agrees with the need to monitor and record the coke burn rate as an operating parameter for a source subject to the PM standard, but the rate is only a calculational parameter and should not be enforceable in its own right in that there should not be a violation if the rate is exceeded so long as the standard is met.

Response: We agree with the commenters' recommendations for adding specific monitoring requirements for uncontrolled CCU regeneration vents (i.e., units without add-on control devices). Having specific requirements will facilitate the permitting process for both the permit applicant and the permit authority. In response to these comments we have revised the proposed rule to include specific requirements.

We also agree with the commenters regarding the role of coke burn rate as a calculated parameter rather than a monitored parameter where a control device is present.   However, the performance of most PM control devices are affected by the gas flow rate (which is directly proportional to the coke burn rate). For example, gas velocity through an ESP is an important operational parameter that affects ESP performance.   As a result, we have revised the proposed requirements for CCU catalyst regeneration vents for those units that are not subject to (or electing to comply with) the PM standard of 1 lb/1,000 lbs of coke burn-off. These units can use gas flow rate monitors or other parameters to determine flow rate (as discussed in comment/response 5.2), rather than coke burn rate as their monitored parameter.

We also agree with the commenters that a CCU catalyst regeneration vent that is subject to the Ni standard (lb/hr), must monitor the E-Cat Ni concentration as well as control device operating parameters. The final rule requires you to measure the E-Cat Ni concentration to determine a site-specific operating limit for the unit. Following the performance test, you must determine and record the weekly E-Cat Ni concentration. We did not select a monthly average E-Cat operating limit as suggested by the commenters because this is too infrequent and does not correlate to coke emission limit. Little or no cost is associated with weekly determinations because most plants already determine the E-Cat on a more frequent basis as a process control parameter. An equation is provide in the rule to calculate the site specific operating limit value for the unit. An excursion from the established E-Cat range or established process/control device operating parameter values would be reported as a deviation from the operating standard.

We do not agree with the commenters that coke burn rate should be the monitored parameters for CCU catalyst regenerator vents not equipped with a control device. For these situations, we have also added specific monitoring requirements. This includes use of a COMS because there appears to be a stronger correlation between particulate emissions and opacity than coke burn rate and PM emissions. For uncontrolled units electing to comply with the Ni standard, gas flow rate and E-Cat Ni concentration are also required monitoring parameters.

If a COMSis used, and you are subject to (or elect to comply with) the PM standard of 1 lb/1,000 lbs of coke burn-off, you must measure the opacity of emissions during the initial performance test and the coke burn rate. This is the same requirement as for NSPS units. If you elect to comply with the Ni standard (lb/hr), you must measure the opacity of emissions during the initial performance test and the E-Cat Ni concentration and gas flow rate. Using the opacity data from the test, you must establish a site-specific operating standard based on the values at the time of the source test. Any 1-hour period over the site-specific value determined for your unit (for non-NSPS units) must be reported as a deviation from the operating standard.

However with regard to overall monitoring requirements, the final rule has been revised to reflect the fact that Federal requirements for State implementation plans (40 part 51, appendix P) require COMS for all CCU with process capacity greater than 20,000 bpd. Consequently, COMS were added to the final rule for all CCU greater than 20,000 bpd. However, as water vapor in wet scrubber exhausts interfere with COMS, parameter monitoring is still the only monitoring method applicable to CCU using wet scrubbers. Those units below the 20,000 bpd capacity cut-off have the choice of COMS or parameter monitoring.

5.6 Repeat Performance Tests for CCU Catalyst Regenerators Subject to Ni Alternative

Comment: Commenters IV-D-30 and IV-D-31 request that EPA reinstate the requirement for biennial performance tests included in the P-MACT document particularly for any unit subject to a Ni standard. Compliance with the Ni alterative can only be verified after confirming the particulate emission rate, the coke burn rate, the E-Cat, and the feed quality. The commenters also recommends that EPA require monitoring of the CCU feed rate on a regular basis and report the quality of feed to the unit on a monthly or quarterly basis.

Response: In the final rule, we are not requiring repeat performance test for those units that elect to comply with the CCU standard formatted in terms of Ni emissions. These units must perform and initial performance test to determine their Ni emissions and must determine their Ni E-Cat concentration during the test. For units greater than 20,000 bpd capacity, this is used as input to determining a maximum operating value (based on opacity, gas flow rate, and E-Cat Ni concentration) that is not to be exceeded during operation of the unit. Although CCU feed rate and feed quality are important parameters that influence the Ni E-Cat concentration, it is also necessary to know the catalyst replacement rate to calculate a value for E-Cat or Ni emissions. Direct weekly E-Cat Ni concentration measurements are a more direct and timely assessment of the E-Cat Ni concentration and adding these additional parameters is unnecessary and burdensome. For those units that are less than 20,000 bpd and are using an ESP or wet scrubber as a control device, continuous compliance also will be based on monitoring of control device operating values. For those units that are less than 20,000 bpd and that do not have these control devices, continuous compliance will be determined based on maintaining a site-specific opacity as measured by a COMS. Given these requirements, we do no feel that it is necessary to require repeat performance test to ensure continuous compliance. For those situations where there is any uncertainty on the part of the Agency regarding compliance, the EPA has the authority under section 114 of the CAA to request a source test to determine compliance.

5.7 Calibration of Temperature Measurement Device for a Boiler or Process Heater Less than 44 MW Where the Vent Stream is Not Introduced into the Flame Zone

Comment: Commenter IV-D-26 refers to the requirements of §63.1565(a)(3)(ii) of the proposed rule which requires the plant to verify the calibration of the temperature measurement device every 3 months. According to the commenter, calibration of the device will not ensure accuracy; calibration should be required of the entire temperature recording system. The commenter suggests that a 6-month frequency would be more reasonable for this requirement

Response: We agree with the commenter's suggestion and revised the proposed rule to require calibration of the temperature recording system (device and recorder) every 6 months.

5.8 Monitoring Exemption for a Boiler or Process Heater Greater than 44 MW Heat Input

Comment: Commenter IV-D-53 questioned why the proposed rule allows CCU with a CO (waste heat) boiler that has a design heat input capacity of at least 44 MW to be exempt from the requirement to install and operate a CEMS or CPMS.

Response: As proposed, the rule does allow CCU with a CO (waste heat) boiler that has a design heat input capacity of at least 44 MW to be exempt from the requirement to install and operate a CEMS or CPMS. The EPA has re-examined whether these CO boilers operate in a manner similar to typical industrial boilers, boilers that served as the basis for the exemption, and whether they achieve equivalent organic compound destruction efficiencies.

A boiler (or process heater furnace) is comparable to a vapor incinerator (a.k.a. thermal oxidizer or afterburner) where the average furnace temperature and residence time, for the most part, determine the combustion efficiency. Thermal oxidizers generally operate in the range of 1,200 to 1,600 ^{o}F and require a minimum residence time of 0.3 seconds in the oxidizing zone. An analysis of test results, along with kinetics calculations, indicate that for a nonhalogenated VOC, a 98% destruction efficiency is achieved by vapor incinerators with a combustion temperature of 1,600 ^{o}F and a residence time of 0.75 seconds.

A review of the technical basis for the original boiler-size exemption shows that a mathematical model was developed to estimate the furnace residence time and temperature profiles for a variety of industrial boilers. This model predicts mean furnace residence times of from 0.25 to 0.83 seconds for natural gas-fires watertube boilers in the size range from 4.4 to 44 MW (15 to 150 x 10^6 Btu/hr). In industrial boilers at or above the 44 MW size, residence times and operating temperatures ensure a 98% VOC destruction efficiency. Furnace temperatures for this range of industrial boiler sizes are at or above 2,200 ^{o}F, with peak furnace temperatures occurring in excess of 2,810 ^{o}F.

In the petroleum industry, the operation of partial-burn FCCU produces gases rich in CO. To reclaim the thermal energy represented by these gases (i.e., the heat of combustion of CO and other organics , and the sensible heat of the regeneration gases), the unit can be designed to include a CO boiler that uses the CO as fuel to generate steam. From the air pollution viewpoint, the CO boiler oxidizes the CO and other combustibles to carbon dioxide and water.

In most cases, auxiliary or supplemental fuel is required in addition to the CO and may be either fuel oil, refinery process gas, or natural gas. The CO boiler may be a vertical structure with either a rectangular or circular cross-section with water-cooled walls. The following design criteria have been established:

1. The basic firing rate should produce a temperature of 1,800 °F in the furnace, to provide safe and stable combustion of the fuels.

2. Air is supplied by the forced draft fan to provide 2% O_2 leaving the unit when burning gases and supplemental fuel.

3. Supplemental firing equipment is provided capable of raising the temperature of the FCCU gases to 1,450 °F which is the temperature needed for ignition of the gases.

The literature also reports that since there are only slight variations in the operation of the FCCU, the boiler is normally base loaded. It handles all the gases from the regenerator regardless of the CO_2 /CO ratio. A change in this ratio merely affects the quantity of supplementary fuel necessary to maintain the required furnace temperature of 1,800 °F. This temperature provides a reasonable operating margin for possible variation in the operation of the regenerator or the boiler.

Regeneration gases from the FCCU are normally delivered to the inlet of the CO boiler ductwork at about 1,100 °F, and 2 psig. When the regenerator gases first pass through an ESP, the inlet gas to the precipitator must be cooled below 500 °F. The CO boiler would then receive regeneration flue gas between 450 and 500 °F. The CO boiler's firebox temperature is also reported in this reference to be between 1,800 and 2,000 °F. The firebox temperatures for CO boilers do not appear to be generally as high as those reported for conventional natural gas fired industrial boilers; however, the CO boiler operating temperatures are above the typical operating range for most high efficiency thermal oxidizers.

Based on the design and operating characteristics of refinery CO boilers for FCCU, it appears that this "control unit operates the same way as an ordinary process unit boiler" and that CO boilers would operate with residence times and operating temperatures that ensure a 98 percent VOC destruction efficiency similar to conventional industrial boilers. Therefore, allowing these units the standard size-based exemption for monitoring is considered appropriate.

5.9 Accuracy and Calibration Requirements for CCU and CRU with Wet Scrubbers

Comment: Commenters IV-D-49, IV-D-53, and IV-D-59 oppose the 3-month calibration requirement for cyclic and semi-regenerative CRU that may not regenerate quarterly. Also, some orifice plates would have to be removed from service to be calibrated, thus requiring a shutdown of the unit. Commenter IV-D-53 suggests calibration every 3 months for cyclic and continuous CRU and prior to regeneration for semi-regenerative CRU (or quarterly, whichever is less stringent). Commenter IV-D-49 suggests calibration at the same time as the CRU regeneration for cyclic and continuous CRU and prior to regeneration for semi-regenerative CRU.

Commenters IV-D-47 and IV-D-53 explain that existing monitoring equipment for CRU with wet scrubbers will not meet the proposed calibration and accuracy requirements. CRU pressure drop monitors are typically in excess of 200 psig and the pressure monitors and ranged accordingly. Five psig is the minimum pressure drop that can be determined with any confidence. Flow rate monitors are typically orifice plates which will not demonstrate accuracy at the $\pm$5 percent level. These devices typically are assessed to be accurate to within $\pm$10 percent. More accurate flow monitoring devices (e.g., insertable turbine meter) are difficult to install and maintain and unlikely to withstand the corrosive characteristic of the gas. He recommends that flow monitors using orifice plates may be calibrated physically and assumed to be accurate to within $\pm$10 percent based on monitor-specific design and condition, inspected during scheduled maintenance once every 3 years or inspected immediately prior to regeneration for semi-regenerative CRU.

Response: We agree with the commenters' suggestion on calibration requirements for monitoring devices for a semi-regenerative CRU equipped with a wet scrubber. In response, we have revised the proposed rule to allow calibration of monitoring devices for a semi-regenerative CRU equipped with a wet scrubber prior to each regeneration. Calibration requirements for monitoring devices for other types of CRU remain at 3 months. We also have increase the accuracy specification for wet scrubber monitoring devices to 10 percent as suggested by the commenters. Additionally, the pressure drop monitoring requirement has been removed as this parameter is specific to Venturi-type scrubbers used for PM control and is not relevant to adsorptive scrubbers, such as those used to control HCl.

5.10 Monitoring Requirements for Catalytic Incinerators

Comment: Commenter IV-D-26 does not consider the daily average upstream temperature and the daily average temperature across the catalyst bed is the best way to monitor catalytic incinerators. If the VOC loading of the process is variable, the temperature rise across the catalyst will vary accordingly. The temperature rise is roughly directly proportional to the VOC concentration entering the catalyst. If the VOC loading is low for a considerable period of time, the temperature rise will also be low even though the catalyst may be performing at the required destruction efficiency. He suggests annual testing of the catalyst and inspection of the oxidizer for mechanical integrity. However, maintaining a preset catalyst inlet temperature is the most common control mode for a catalytic oxidizer.

Response: We agree with the comment in general; however, we do not expect any one to use this type of control technology for their CCU, CRU, or SRU vents and therefore, have dropped the provisions from the rule.

5.11 Monitoring Requirements for CRU With Internal Scrubbers

Comment: Commenters IV-D-47 and IV-D-53 state that pressure drop and gas flow rate are not appropriate operating parameter to be monitored for CRU with internal scrubbers. Internal scrubbers are different because they do not use trays or packing to promote liquid-gas contact. Typically, these unit are characterized by liquid injection into the regeneration gas stream followed by liquid removal in a gas-liquid separator vessel. Pressure drop can be caused by fittings, heat exchanger tubes, and other obstructions instead of a scrubber tower containing trays or packing. Measurement of gas flow rate is a problem. This is typically measured using orifice plates. These type of plates will not provide an accurate measurement of gas flow during the regeneration process. In some systems, the location of the plate will not provide a measurement of total flow to the scrubber. In these systems, the plate would have to be relocated or additional flow measurement devices would have to be installed to account for the addition of other streams. They recommend revising the proposed rule to distinguish between an external scrubber using trays or packing and an internal scrubber where only the gas flow rate and total water (or scrubbing liquid) flow rate to the scrubber would be monitored.

Response: The proposed standard did not require monitoring of pressure drop and gas flow rate for CRU with no add-on control devices. The proposed standard required the owner or operator to include recommended monitoring requirements in the part 70 or part 71 permit application. As discussed in comment/response 5.7, the pressure drop monitoring requirement for CRU wet scrubbers was also dropped. In addition, we have added specific requirements to the final rule and clarified the language in the rule to distinguish between units with an add-on control device (i.e, wet scrubber) and no add-on control device (internal scrubbing system). These requirements include a initial performance test to measure HCl emissions with EPA Method 26 and during subsequent regeneration periods monitoring of the HCl emission concentration every 4-hours during the coke burn and rejuvenation cycles using colorimetric methods such Draeger tubes.

5.12 Continuous Emission Monitoring

Comment: Commenters IV-D-26, IV-D-31, IV-D-46, and IV-D-56 urge EPA to require CEMS. Commenter IV-D-31 supports requirements for HCl, TRS, and either CO or THC or TOC for all new sources rather than the limited requirements in the proposed standard because they are feasible (as stated in the BID), ensure standards are met at all times, and provide better HAP monitoring. If these technically-proven systems are in place at more than 12% of existing refinery sources, then they should be required for existing sources as well as new sources. Commenter IV-D-26 also urges EPA to require CEMS where proven in similar service. The cost of these systems is decreasing and they may no longer be too costly. The continuous monitoring of a process allows the operator greater flexibility in operation which could result in increased output, improved efficiency, and overall cost savings. Commenters IV-D-46 and IV-D-56 specifically request CEMS for TRS limits. CEMS for TRS are commercially available currently used at a number of Texas refineries to demonstrate compliance with the NSPS. Due to the TRS emissions from refineries and numerous exceedances, more accurate information is needed to assess compliance than operating parameter values.

Response: We agree with the commenters' recommendations that NSPS experience with CEMS demonstrate their technical and economic feasibility for this industry, provide better data, and need to be encouraged. In determining monitoring requirements, EPA looks at the various options from a top-down approach. One of the options examined was requiring CEMS or COMS for all affected sources under this rule. We did not select this option because of the high capital and operating costs. However, we have re-examined these options after proposal and looked carefully for ways to encourage their use or require their use if needed. As a result, we have included options in the rule allowing plants to choose to comply with the NSPS limits and the corresponding monitoring requirements. We have also included requirements in the rule for the use of COMS for catalyst regeneration vents for CCU with throughput capacity greater than 20,000 bpd (and not using wet scrubbers) and have added COMS as a monitoring option for smaller CCU (see comment/response 5.5). COMS are required for the larger units under State implementation plan requirements in 40 Part 51, Appendix P; therefore these costs are not attributable to this rule.

A CEMS for TRS emissions also is required for SRU with no add-on control device. The cost of CEMS for these units is reasonable and does not pose any economic hardship for plants that do not use a control device. The Agency is also confident that in those cases where process or control device parameter monitoring is allowed in place of a CEMS, that this provides adequate assurance of continuous compliance.

5.13 Annual Stack Tests

Comment: Commenters IV-D-31 and IV-D-56 recommend that annual stack testing should be required to confirm the integrity of the process values used for parametric monitoring wherever continuous emission monitoring is not used. An example is premature wear of components within the CCU due to the abrasive nature of the catalyst fines which can lead to changes in particle size distribution and increased quantities of fines to the control equipment. Either of these conditions could lead to decreased efficiency of the collection device with no measurable change in the monitored process values.

Response: The EPA feels that the monitoring requirements in the final rule which are based on the “top down” monitoring approach are adequate to ensure continued compliance for these refinery units. The use of CEMS, COMS, and CPMS as appropriate eliminates the need for repeat source tests. Therefore, the final rule does not include requirements for annual or repeat stack tests. The EPA regions can use the section 114 authority under the CAA to request a source test should they believe there is premature wear of process or control device components that would result in increased loading to the control device and/or increased emissions to the atmosphere.

5.14 ESP Plate Area and Conditioning Agents

Comment: Commenters IV-D-41, IV-D-31, and IV-D-56 recommend that EPA request data on the ESP plate area (square feet per 1,000 actual cubic feet per minute of gas flow). EPA could also require a minimum plate area of 300 to 350 square feet per 1,000 actual cubic feet per minute for reliable performance with the PM NSPS. EPA also should request information on the use of humidification or commercial conditioning agents since they enhance ESP performance to ensure that such agents are used routinely and not merely during performance tests.

Response: The EPA did collect considerable information on the ESP plate area used for these devices when applied to CCU catalyst regeneration vents. The information and data were used in the control device designing and costing efforts. However, we did not include a design or equipment specification standard in the CCU standards because the prescription of a performance standard was feasible and thus takes priority over establishing an equipment standard. We have taken the commenters recommendation and revised the performance test and recordkeeping requirements to require the owner or operator to maintain records on subsequent use of any condition agents used during and after the performance test. Additionally, we have modified the ESP monitoring requirement to include actual gas flow rate through the ESP as this is a key parameter in ESP control efficiency given a fixed plate area.

5.15 Opacity Monitoring for Non-NSPS CCU

Comment: Commenter IV-D-43 believes opacity monitoring, coupled with control device operating parameter monitoring, is a better measure of compliance with the PM standard for CCU regenerator vents as compared to coke burn rate. NonNSPS units should have the option to elect opacity monitoring identical to the NSPS requirements even though they are not subject to the NSPS.

Response: We agree with the commenter and included the NSPS requirements as an option for "non-NSPS" affected sources in the final rule. Because data from these systems will be used to demonstrate initial and continuing compliance, continuous emission and opacity monitoring systems must meet the operation, maintenance, and quality assurance requirements in the NESHAP General Provisions and the requirements of each applicable performance specification in Appendices B and F of 40 CFR Part 60. As discussed in other responses, opacity monitoring requirements have been added to the final rule such that those CCU with a throughput greater than 20,000 bpd and not using a wet scrubber are required to install and operate a COMS. Again, this requirement is based on the state implementation plan requirement in 40 CFR Part 51, Appendix P.

5.16 Daily Averages for Monitoring Systems

Comment: Commenter IV-D-46 opposes daily averages for combustion device operating parameters, such as combustion temperatures. Use of daily averages for combustion unit performance averaging times will allow short term high emission transients associated with combustion upsets. These short term events will frustrate the entire purpose of establishing a standard for organic HAPs. All averaging times for compliance purposes on both emissions and parameter monitoring should be revised to be no longer than 1-hour.

Response: The EPA agrees that the monitoring of process and control device operating parameters should be done in terms of hourly averages and we have revised the final rule to specify monitoring data collection in terms of hourly averages. We have not however revised the designations of the operating standards (i.e., previously referred to as excess emissions for control devices) that were proposed in terms of a 24-hour average. The short term fluctuations of the control device operating parameters is not expected to have a significant influence on the overall emission levels for these units. Therefore, as was done for this source category in the initial refinery standards (i.e., MACT I) for process vents and other organic source control devices, the designation of operating standard is made in terms of 24-hour averages in most cases. Any deviation from these operating standard values is required to be reported to the Administrator.

5.17 Draeger Tubes for Monitoring of Scrubbers

Comment: Commenters IV-D-47, IV-D-49, IV-D-53, and IV-D-59 recommend allowing the use of Draeger tubes for the monitoring of emissions from CRU scrubbers. This is a common practice in the refining industry and can be easily incorporated in the monitoring requirements. Commenter IV-D-59 specifically requests use of Draeger-type colorimetric tubes or monitoring the condensate pH to determine compliance with HCl emission standards for semi-regenerative CRU. The commenter contends that outlet monitoring using the appropriate EPA test methods is technically infeasible because the vent is at the top of the vessel and thus, not designed for worker access. Worker exposure to pressure relief valve discharges would be dangerous and would not be allowed by company or federal occupational safety rules. Also, the vent outlets do not have the geometry needed for stack testing. This commenter operates a semi-regenerative unit with an internal scrubber for caustic spray injection.

Response: The proposed standard required the owner or operator to include recommended monitoring requirements for CRU with no add-on control device such as the configuration described by the commenter (i.e., semi-regenerative unit with an internal scrubbing system). Outlet monitoring may not be a feasible approach for the reasons described by the commenter. For this reason, we revised the rule to require Method 26 rather than 26A for performance tests and to include specific procedures for monitoring CRU with no add-on control device that allow use of colorimetric methods. Colorimetric (e.g., Draeger) tubes can provide reasonable performance monitoring in this particular set of circumstances. The monitoring procedure varies according to the concentration range to be measured. For example, a continuous pump may be required over a hand pump in some cases. Monitoring the pH of the scrubbing solution condensate is also considered to be an appropriate measure of scrubber performance for these system applications, and pH monitoring requirements have been added to the rule for CRU.

5.18 Method 26 vs Method 26A for HCl Emissions from CRU

Comment: Commenters IV-D-47 and IV-D-53 believe Method 26A for determining HCl concentration and mass flow rate may not be feasible for CRU due to potentially hazardous process conditions at sampling locations. For example, determination HCl removal efficiency by a CRU internal scrubber using Method 26A may be difficult and dangerous due to system operating conditions at the scrubber inlet (high temperature and high pressure). Safety considerations prohibit the use of 26A for quantifying the HCl content of the inlet gas. Alternative sampling procedures to determine HCl and mass flow rate are needed. The commenter recommends the non-isokenetic Method 26 as an alternative with a sampling rate of at least 0.001 dry standard cubic meters per minute. To calculate HCl mass flow rate, the gas flow rate at the inlet and outlet of the control device may be determined using the calibrated process flow monitoring equipment.

Response: We agree that it may be technically difficult to measure a percent reduction for a CRU that use internal scrubbing systems, i.e., with no add-on control device. Concentration standards were included in the rule for this reason. We also agree that the non-isokenetic Method 26 with the sampling rate recommended by the commenter should be used for performance tests for this situation and have revised the rule accordingly.

5.19 Monitoring Requirements for SRU without Combustion Device

Comment: Commenters IV-D-47 and IV-D-53 recommend that monitoring requirements for SRU without a combustion device (i.e., a tail gas cleanup unit) be included in the rule rather than requiring the owner/operator to submit a recommended CPMS. The commenter recommends that EPA adopt the monitoring requirements in §60.105(a)(6) and (a)(7) of the NSPS for this source.

Response: We agree that specific monitoring requirements should be included for SRU with no add-on control device and have revised the proposed rule to include the provisions recommended by the commenter. These are the NSPS monitoring requirements for Claus SRU with reduction control systems not followed by incineration. Section 60.105(a)(6) and (a)(7) require a CEMS to measure the concentration of reduced sulfur and O_2 emissions with a span value of 450 ppm reduced sulfur and 10 percent O_2. Provisions also are included for performance evaluations by Performance Specification 5 for the reduced sulfur and O_2 monitor and for using an air or O_2 dilution or oxidation system that converts the reduced sulfur to SO_2 as an alternative to a reduced sulfur monitor.

5.20 Monitoring Requirements for Flares

Comment: Commenter IV-D-56 recommends that the rule require routine testing of all emergency and process flares rather than routine monitoring since facilities claim a combustion efficiency of 95% or more, but do not base their claims on actual emission test results. The actual combustion efficiency needs to be demonstrated and not merely assumed. EPA needs to address methods for flare testing with available technology such as remote sensing systems, ultraviolet, infrared lasers, and other technologies.

Response: We agree with the commenter that there are more modern methods for flare testing that are rapidly becoming available and EPA will be looking at these in the near future. However, the flare provisions in 63.11 of the NESHAP General Provisions do include requirements to ensure that flares are properly sized and operate according to their design and these design requirements were based on a 98% destruction efficiency. Testing of flares is not being required in the final rules.

5.21 Exceedances and Excursions

Comment: Commenter IV-D-25 does not support allowing one exceedance or excursion by the same control device during a 6-month period. This may allow the facility to exceed the standard once regardless of whether it can justify the exceedance. Problems that occur regularly but infrequently may also be ignored. Further, the "one exceedance" standard eliminates enforcement discretion in addressing these types of exceedances or excursions. EPA should adopt the proposed rule without the condition that requires one or more exceedances or excursions in a semi-annual period to be a violation. Commenter IV-D-56 strongly opposes allowing potential exemptions for one excursion per semi-annual reporting period. The commenter describes several problems with specific refineries in his community regarding exceedances to SRU upsets. EPA must not allow such excursions to take place without appropriate enforcement, penalties, and corrective actions.

Commenters IV-D-39, IV-D-47, and IV-D-53 believe the proposed rule should be made consistent with the NESHAP for Hazardous Organics from the Synthetic Organic Chemical Manufacturing Industry (HON rule). Here, six exceedances or excursions are allowed during the first semi-annual period. The number of excused exceedances or excursions is then reduced by one for each successive reporting period until the sixth period. From the sixth period onward, only one exceedance or excursion is allowed. Commenter IV-D-59 requests that EPA adopt the NSPS requirements for reporting emission exceedances and monitoring system malfunctions. Here, additional information is requested once a reasonable percentage threshold has been exceeded.

Commenter IV-D-53 asks that "exceedance", "excursion", and "violation" be defined, that the requirement for 75% percent data availability not automatically trigger an excess emissions report, and that provisions be added for gaps in monitoring data used to verify compliance. This can be done in a way similar to the NSPS where if the duration of monitoring malfunctions is greater than 5% of the operating time for the period, a higher level of reporting detail is required.

Response: In the final rule, the EPA has revised the format and terminology used in the rule and no longer uses the terms “exceedances”, “excursions”, “excess emissions”, and “violations”. The final rule uses the term “deviation” rather than “exceedance,” or “excursion,” etc. A deviation is any instance in which an affected source or the owner or operator or an affected source: (1) fails to meet any obligation or requirement in the rule, (2) fails to meet any term or condition in the operating permit, or (3) fails to meet any emission limitation or work practice standard during startup, shutdown, or malfunction regardless of whether or not the failure is permitted by the rule. Consistent with §63.6(e), we (the EPA) will determine if a deviation is a violation of the NESHAP. Under the new NESHAP format, these provisions are being included in new MACT standards to improve the understanding and consistency of our rules.

The final rule retains the 75% data availability requirement for CPMS. Obtaining the required monitoring data for 75% of the hours the process operates is the basic method of demonstrating continuous compliance if you use a CPMS. The final rule does not include provisions for filing data gaps using alternative monitoring procedures. Plant owners and operators can use a backup monitoring system for this purpose or apply to EPA for approval of an alternative parameter or monitoring method for use when the primary system fails.

The information to be reported in the semiannual reports required by the final rule is nearly identical to the information required for the NSPS excess emission reports except that there is no 5% trigger for the duration of monitoring malfunctions. Any deviation must be reported, including a startup, shutdown, or malfunction.

Under the new format, we have established operational standards for continuous compliance with emission limits and parameter monitoring. For example, the owner or operator must establish a minimum operating temperature for any thermal vapor incinerators used as control devices. Similar parameter values must be established for other control device types and process parameters as specified in the rule. In establishing the operating limits, we strongly considered the NSPS definitions of conditions that constitute excess emissions or violation that take into account process and control device fluctuations over time. In addition, the final rule does not provide for a fixed (or declining) number of deviations over each reporting period as is done in the HON rule. No data were available to define or establish the conditions, or a typical number of exceedances or deviations, that occur over a given time period under what could be termed normal operations.

6.0 PERFORMANCE TEST REQUIREMENTS

6.1 Determine Reactor Pressure During Performance Test

Comment: Commenter IV-D-27 recommends that CCU reactor pressure be recorded during the initial performance test. It is not uncommon for a source to continue operation with one or two fields down in an ESP. A worst case stack test would include determining how many fields can be down before maintenance is performed or load must be dropped.

Response: We agree that it is important to know ESP performance and operating conditions especially during a performance test. However, reactor pressure is not the most direct measure of control system performance for ESP applied to CCU vents and it is not being utilized as a performance measure in the final standard. We have revised the rule to require recording of the total number of fields in the ESP and how many are operated during the performance test. We are also requiring that the owner or operator maintain records of any change in the number of fields operating of the ESP over time.

6.2 Determine Maximum Amount of Recycle During Performance Test

Comment: Commenter IV-D-27 says a wet scrubber can operate with 100% fresh feed during a stack test but run some percentage recycle during normal operation. A worst case stack test would be the maximum amount of recycle a source would use. This could also be included as a parameter for excess emission determinations.

Response: We agree that the amount of make-up scrubbing liquid used is an important factor in scrubber performance for HCl scrubbers; we do not believe that the efficiency of the CCU PM scrubber will be strongly related to the amount of recycle used, however. We considered having recycle scrubber liquid as a monitored parameter but decided against it since it is not a direct measure of control device performance and it limits operational flexibility. We have concluded that the most critical parameter that relates to scrubber efficiency for a HCl scrubber while not limiting operational flexibility is pH of the scrubbing liquid. We have revise the rule to record the pH of the scrubbing liquid during the performance test and to require a minimum pH operating parameter limit that must be maintained.

6.3 Determine All HAP Metals During Performance Test

Comment: Commenter IV-D-28 urges EPA to require the CCU catalyst regenerator vent performance test to include all relevant HAP metals because of the current lack of emission data and the need to develop residual risk standards in the future.

Response: The EPA agrees with the commenter that additional metal HAP data would be useful in developing the residual risk standards in the future. However it did not seem reasonable to require that those facilities that chose to comply with the PM standard be required to analyze for the HAP metals. On the other hand, facilities conducting a performance test to comply with the Ni standard could obtain this data at the lowest incremental cost. Therefore, the performance test requirements for facilities complying with the Ni standard include determining and reporting the concentrations for other metal HAP in addition to Ni.

6.4 Conditions Requiring New Performance Tests

Comment: Commenters IV-D-43, IV-D-49, and IV-D-59 oppose new performance tests due to changes in process or operating conditions while Commenter IV-D-27 recommends that change in catalyst or switching from a clean catalyst to a used catalyst should be added to the list of examples because either of these can result in increased PM and/or opacity. Commenter IV-D-43 opposes the requirement to retest because it is redundant to the prevention of signification deterioration and new source review rules that require an emissions impact analysis for unit operations and operational changes that might increase emissions. Also, feedstock change and capacity increase are not always precursors to an increase in particulate emissions. Events most likely to create an increase are those where particulate-contact elements of the process or control device are replaced or modified. Commenter IV-D-49 opposes the requirement based on feedstock changes. He explains that CCU operate over a range of process conditions, some of which are seasonal and some are frequently repeated. Feedstock changes by themselves do not cause changes in HAP emissions and this is not required by the NSPS. This commenter believes the provisions can be interpreted by enforcement agencies to require retesting for any number of process condition changes.

Response: The final standards do not contain any requirements that would directly call for a repeat performance test. Under the final rule, a repeat performance test may be conducted as part of the owner or operator efforts to change the established level of control device or process operating parameters. When changing these values the owner or operator may conduct a performance test, a performance test in conjunction with an engineering assessment, or simply conduct an engineering assessment to verify that, at the new control device or process parameter level, the unit complies with the applicable emission standard. Under the final rule, you must establish a revised value for the monitored process or operating parameter to determine or demonstrate compliance under the new operating conditions if any change to the process or operating conditions (including but not limited to changes in catalyst, feedstock, capacity, control device or capture system) that could result in a change in the control system performance has been made since the last performance or compliance tests or assessments were conducted. The repeat performance test requirements were dropped because the monitoring requirements for the CCU were enhanced (COMS, etc., see comment/responses 5.4 and 5.10) so that compliance with the emissions standards can be assured without requiring additional source tests.

6.5 Test Conditions for CCU Regenerator Vent

Comment: Commenter IV-D-43 opposes the provisions in §63.1564(e) of the proposed rule for conducting the initial performance test at the maximum operating capacity for the process and while operating the control device at conditions which result in the lowest emission reduction. The maximum operating capacity does not represent severe conditions for the control device and operating the control device at conditions which result in the lowest emission reduction implies testing under end-of-run conditions. The commenter recommends stating that the tests should be conducted under conditions that characterize the throughput and operating conditions projected for the control device under the current configuration of the process.

Response: The EPA agrees with the comment and has revised the performance test requirements such that the test can now be conducted under conditions that characterize the unit operating conditions that are representative for the unit and control device under the current configuration of the process operations. Monitored operating parameters that are measured during the test to establish the appropriate operating range for the process or control device can be adjusted or revised based on the test data at representative conditions and engineering analysis to set the maximum conditions for the parameter values used to show continuous compliance. The final rule also includes equations to be used to adjust certain operating limits when the control variables are expected to be linearly related.

6.6 Use of Engineering Analysis to Establish Limits for Process/Operating Parameters

Comment: Commenters IV-D-47, IV-D-49, IV-D-53, and IV-D-59 believe that engineering analyses are needed to adjust performance test results used to establish process or operating parameter values. According to the commenters, it is unlikely that tests will be conducted under worst cases conditions. It is more likely that an affected source will operate at a level below the standard during the compliance test and the operating parameters established during the test will be unduly low. Therefore, the results of the performance test need to be adjusted to be equivalent to the proposed standard. It also is unlikely that the control device can be operated at worst case conditions. Without a CEMS, the operator really doesn't know at what point the control device has been turned down too far and exceeded the limit.

Response: As noted in the previous response, under the final rule EPA allows that monitored operating parameters measured during the performance test to establish the appropriate operating range for the process or control device can be adjusted or revised based on the test data at representative conditions and engineering analysis to set the maximum conditions for the parameter values used to show continuous compliance. For certain conditions, appropriate equations have been added to the rule to aide in making these adjustments.

6.7 Performance Test for Organic HAP from CCU

Comment: Commenter IV-D-43 believes that the performance test should be the same for NSPS and nonNSPS CCU. An initial Method 10 test should be the measure of compliance for the MACT just as for the NSPS. Under the proposed MACT, EPA treats the CO CEMS readings (of units required to install them) as if they are a compliance measure. This is not the case for NSPS compliance where an instantaneous reading over 500 ppm is only an indication that the unit has gone out of equilibrium due to a process fluctuation; and is not a violation or non-compliance event. The commenter also noted that corrective measures typically require more than an hour to restore equilibrium.

Response: It is important to note that NESHAP requirements under section 112 differ greatly from NSPS provisions under section 111. For one thing, the CAA requires a reasonable assurance of continuous compliance for MACT standards under section 112. And, continuous monitoring data provide this evidence of compliance. Therefore in the final MACT standard provisions are included that establish requirements for continuous compliance or operating limits. Any deviation from the operating limits must be reported to the permitting authority in the semi-annual report. Consistent with §63.6(e), the EPA will determine if a deviation is to be considered a violation of the standard. Under section 112, a violation can be assessed with a financial penalty for these operating standard violations. The commenter is correct in that a violation of the NSPS emission limit can only be determined through a source test.

6.8 Early Compliance Certification

Comment: Commenter IV-D-43, IV-D-49, and IV-D-59 asks that the final rule allow the performance test to be scheduled anytime during the 3-year compliance window after promulgation, plus 150 days. This will alleviate any potential scheduling problems due to the shortage of qualified stack testing firms. A facility should not have to wait until the proposed testing period because most facilities will see if they can achieve compliance without controls and such testing must be done well before the final compliance date. Testing for newly installed controls also needs to be performed prior to the compliance date so that adjustments can be made if needed.

Response: The point made by the commenter is valid. We have revised the rule to change requirements for the performance test report to provide for the initial performance test and report anytime from the date of promulgation of the final rule to the date 150 days after the compliance date (3 years from the promulgation date). In this way, you, the owner or operator, can do your performance test and test reports anytime from the date of promulgation or the next 3 year period. However, the performance test and report must not be any later than 150 days after the 3-yr period.

6.9 Equation 2 for Calculating Coke Burn-off Rate

Comment: Commenters IV-D-47, IV-D-48, and IV-D-53 state there should not be a percent in the denominator of the constant K_2. In Equation 2 for coke burn rate in the proposed rule.

Response: We agree with the comment; the inclusion of the percent symbol was a typographical error and it has been removed from the final equation.

6.10 Alternative Coke Burn Rate Equation

Comment: Commenters IV-D-49 and IV-D-59 request use of site-specific equations for coke burn rate. Commenter IV-D-49 states a several methods are used in the industry to calculate the coke burn rate; the usefulness of the calculation depends on its repeatability. The rule needs to allow any reasonable alternative calculation method. This would provide flexibility in monitoring emissions and be consistent with site-specific current practices. The alternative calculation would be calibrated to the EPA method during the performance test. For example, if emissions during the stack test are 1 lb particulate/M lbs coke with a coke burn rate of 28,000 lbs/hr using EPA coke burn calculations and the equivalent alternative process calculations show a coke burn rate of 30,000 lbs/hr, the target coke burn rate is 30,000 lbs/hr and not 28,000 lbs/hr.

Response: We feel that it is important for both implementation and enforcement that there be a single equation for this parameter. Therefore we are maintaining the single equation to provide a consistent method of making the determination.

6.12 Method 5B and 5F for PM

Comment: Commenters IV-D-49 and IV-D-59 support use of Method 5B and 5F to measure PM. According to the commenter, these methods measure the portion of the PM that relates to HAP by subtracting out the condensible sulfate particulate. There is no Ni in the condensible particulate portion of the CCU regenerator vent emissions. State standards for PM vary according to their purposes and specifying 5B or 5F regardless of the State requirements would insure consistency.

Response: EPA has maintained the use of Method 5B and 5F in the final rule to allow the owner or operator to deduct or subtract the mass of sulfate PM measure during the performance test. This fraction of the sample would not have any HAP metals and therefore should not be counted in the results. We should also point out that the final rule does not include use of Method 18 for organic HAP because of technical limitations with this method as applied to CCU.

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7.0 STARTUP, SHUTDOWN, MALFUNCTION, AND MAINTENANCE

7.1 Provisions for Planned Maintenance

Comment: Commenters IV-D-37, IV-D-42, IV-D-44, IV-D-47, IV-D-49, IV-D-53, and IV-D-59 state that provisions are needed to accommodate planned maintenance of control equipment, particularly for the CCU regenerator. The commenters feel that the CCU should be allowed to operate during periods when the control device is out of service for maintenance overhauls because the use of preventative maintenance results in less environmental impacts. Commenter IV-D-43 adds there should be provisions in the rule for unanticipated maintenance downtime for control devices while the CCU is running. Full unit shutdown and startup to repair such devices results in a greater risk of excess emissions than performing an on-line repair where possible.

According to the commenters the industry average for CCU turnarounds is 4-6 years and up to 10 years for an ESP or wet scrubber. Preventative maintenance is needed more frequently. The turnaround process typically takes about four to six weeks. Provisions for planned maintenance have been adopted by Texas, California, New Mexico, and Louisiana and Montana has a provision calling for annual shutdown of the CO boiler for routine inspection and maintenance. Commenter IV-D-37 also discusses cases where a control device, such as a wet scrubber, is common to two CCU. Facilities with a unit sharing common control equipment can not turn around both units at the same time. For this reason, plants need to shutdown the control equipment during every other scheduled turnaround. The commenter does not believe it is reasonable to require redundant control systems due to the costs, the infrequent nature of downtimes, the resulting emissions, and the economic penalty to the refinery associated with shutdown of a major process unit. This commenter recommends the final rule include provisions allowing, subject to approval by the applicable permitting authority, that would require the SSMP to include specific steps to minimize emissions during a planned maintenance period. Such a plan might specify that the site conduct ambient air quality monitoring to ensure that CO and PM standards are not exceeded.

Commenter IV-D-42 explains how flue gas diversion devices and by-pass stacks are used to allow continued operation of the CCU when the control devices are out of service for mechanical repairs. The commenter also discussed how malfunctions require a by-pass of control devices or may cause a control device to shutdown while the unit continues to operate. The commenter suggests that short duration exceedances be allowed for control device startups, shutdowns, and malfunctions. These emissions may remain estimated but not monitored; the magnitude of the emissions can be limited by setting duration limits.

Commenters IV-D-30, IV-D-31, and IV-D-56 believe EPA should include requirements for industry to estimate uncontrolled emissions of criteria and metal HAPs during such a maintenance period and require the facility to make up for the released emissions during periods of normal operation by "over controlling". For example, additional emission reductions can be achieved by fabric filters, improving ESP performance with more plate area or increasing the power supply/voltage, increasing pressure differential on scrubbers, using SO_x reducing catalysts, and reducing CO_2 emissions by employing catalysts that reduce coke make. The commenters also recommend that the rule require plants to collect data during abnormal operations because it is important for the regulatory authority to know the volume of uncontrolled emissions as well as the frequency and duration of emissions. Commenter IV-D-29 asks EPA to consider limiting the number of times a facility would be allowed to have excess emissions resulting from non operation of a CCU control device during planned routine maintenance. Commenter IV-D-46 believes monitoring averages should include periods of non-operation of emission control devices. Failure to operate a control device should be discounted by allowing the source to escape the deterioration of a measured parameter implicit in such a circumstance.

Response: The EPA would like to encourage planned maintenance related to both processes and control devices, especially when that maintenance yields an environmental benefit. However, only one of the commenters provided any substantive information on what particular planned maintenance events they specifically would like to perform and the net environmental benefit achieved by these actions. Consequently, in response to these comments, we revised the rule to include provisions allowing the permitting authority to approve a period of planned routine maintenance for a refinery with multiple CCU served by a single wet scrubber emission control device. During this pre-approved time period, the refinery may take the control device and/or one of the process units out of service for maintenance while the remaining process unit(s) continues to operate. To obtain approval, you must submit a written request at least 6 months before the planned maintenance is scheduled to begin that contains the specified information and data. This includes:

- A description of the planned routine maintenance and why it is necessary;
- The date the maintenance will begin and end;
- A quantified estimate of the emissions (including HAP and criteria pollutants) that would be released with an analysis of the environmental benefits (i.e., emission reduction) that would result as opposed to delaying the maintenance until the next unit turnaround;
- Actions to be taken to minimize emissions during the period.

You must include a copy of the request in the compliance report due for the period before the planned maintenance is scheduled to begin. In the compliance report due after the routine planned maintenance is complete, you must provide followup information on the maintenance including the number of hours the control device did not operate.

Other than the situation discussed above, the rule does not excuse or exempt the refinery owner or operator from meeting the specified emission limits and monitoring requirements during periods when the control device is not in operation; this would include periods of control device startup, shutdown, and malfunction.

7.2 Storage of Intermediate Products Through Duration of Maintenance

Comment: Commenter IV-D-27 explains that during SRU maintenance shutdowns, the sour gas was routed to the flare for about 2 weeks every 1 or 2 years and the refinery was subsequently required to permit the emissions. Afterwards, when the maintenance was scheduled, the refinery would store intermediate products that had already been cracked to last the duration of the maintenance. The final rule should address this type of scenario.

Response: The Agency does not have adequate industry-wide data on the operating practices for these units during process turnarounds to formulate the type of work practice standards that the commenter recommends.

7.3 Maintenance Plan Requirements

Comment: Commenters IV-D-37, IV-D-47, and IV-D-53 oppose the proposed requirement for a maintenance schedule consistent with the manufacturer's instructions and recommendations for routine and long-term maintenance in the maintenance schedule. According to the commenters, manufacturer recommendations are designed to support their warranties and to protect from claim; emissions are not their primary consideration. EPA does not have the data to support their position that strict adherence to the manufacturers recommendations results in decreased HAP emissions or that the best plants in the industry are strictly adhering to these practices. The commenter finds the proposed requirement unnecessary and overly restrictive. Maintenance requirements should be consistent with practices needed to ensure good air pollution control as required by the NESHAP General Provisions.

Response: We have maintained the language in the requirement that maintenance should be consistent with the manufacturers' recommendations; but have clarified that this does not mean that the facility must strictly adhere to the manufacturers instructions or that the facility maintenance plan must be identical to the manufacturers' recommendations.

7.4 HAP Emissions from Startup, Shutdown and Upset Conditions

Comment: Commenter IV-D-28 recommends that the potential HAP emissions associated with startup, shutdown, and upset conditions of the SRU and CCU be addressed in the final rule. At minimum there should be test requirements to determine emissions when elevated levels of HAP are likely because these data will be needed in future residual risk assessments.

Response: The EPA, under the General Provisions to 40 CFR Part 63, specifies requirements associated with startup, shutdown and malfunctions. We did not include specific provisions in this rule for testing or reporting of HAP emissions during these periods and did not include them in the impact analysis for the rule.

7.5 Reporting Malfunction Events

Comment: Commenters IV-D-46 and IV-D-56 do not agree that the proposed rule should allow a source to report only those malfunction events that were not managed in accordance with the startup, shutdown, and malfunction event. All malfunction periods should be reported immediately and in quarterly rather than semi-annual reports. All excess emission events should be considered as potential violations.

Response: The EPA's Part 63 General Provisions do this (i.e., allow a source to report only those malfunction events that were not managed in accordance with the SSMP) to reduce reporting burden. However, these events must be reported in the next semi-annual report. The EPA will determine whether the deviation that occurs during a startup, shutdown, or malfunction is a violation according to §63.6(e).

8.0 RELATIONSHIP TO NSPS AND OTHER RULES

8.1 Relationship of NSPS to MACT Standard

Comment: Comments on the proposed rule revealed a wide range of interpretations on the relationship of the refinery NSPS to the MACT standard and questions regarding which requirements apply under different situations. These comments seem to fall into three categories: (1) whether NSPS are or are not affected sources under the MACT standard, (2) are excess emissions and malfunctions by an NSPS unit subject to the provisions under section 111 or section 112, (3) is CEMS data from an NSPS unit directly enforceable as it would be under a MACT standard and are NSPS units required to comply with Appendix F (not presently required), and (4) can plants select to comply with the NSPS or MACT standard and do the various options under the MACT standard apply to NSPS units.

Response: Because of the wide range of questions and interpretations about the status and requirements for NSPS units, we have revised the proposed rule to explicitly state all requirements. First, all FCCU and SRU are affected sources under this NESHAP. This includes units subject to the NSPS and those that are not. Second, the requirements of this rule in no way change the NSPS requirements. A unit that is subject to the NSPS must comply with all NSPS requirements. To reduce regulatory overlap, the requirements of this rule for the control of HAP contain portions of the emission standards and monitoring requirements of the NSPS. For a FCCU catalyst regenerator vent subject to the NSPS for PM emissions, the HAP metal emission limits are the same as the PM emission limits in 40 CFR 60.102; the HAP metal monitoring requirements for FCCU catalyst regenerator vents are the same as the NSPS requirements in 40 CFR 60.105(a)(1), 40 CFR 60.105(c), and 40 CFR 60.105(d). For a FCCU catalyst regeneration vent subject to the NSPS for CO emissions, the HAP organic emission limit is the same as the NSPS limit in 40 CFR 60.103 and the monitoring requirements are the same as the NSPS requirements in 40 CFR 60.105(a)(2). For a Claus SRU over 20 long tons per day subject to the NSPS for SO_x, the HAP organic (sulfur) limits are the same as the NSPS emission limits in 40 CFR 60.104(a)(2) and the monitoring requirements are the same as the NSPS requirements in 40 CFR 60.105(a)(5).

No performance test or performance evaluation for COMS or CEMS are required to demonstrate initial compliance with MACT rule for units currently subject to the NSPS. However, the owner or operator must certify in the notification of compliance status report that each unit subject to the NSPS is in compliance with the applicable emission limit and monitoring requirements in this MACT standard. The EPA or State permitting authority may request a test to verify compliance with the NSPS if there is any question about the certification.

The NSPS does not require that data from COMS or CEMS be used to determine compliance. Under NSPS, a source test typically is required for this purpose. Under NESHAP, however, data from the COMS and CEMS are used to determine compliance. For this reason, the COMS and CEMS must be operated to meet the applicable performance specifications in appendix B to 40 CFR Part 60 and the quality assurance requirements in appendix F to 40 CFR Part 60. Appendix F provides detailed procedures for conducting daily calibration drift checks and quarterly relative accuracy audits for CEMS. These may be a new requirement for some plants. Other requirements for continuous monitoring systems in § 63.8 of the NESHAP General Provisions plants are:

- Conduct daily calibration drift checks (low-level and high-level) and adjust the low-level and high-level drifts whenever the 24-hour low-level drift exceeds two times the limit of the applicable performance specification. Clean all optical and instrumental surfaces exposed to effluent gases before making adjustments and whenever the cumulative automatic zero compensation (if applicable) exceeds 4 percent opacity

- If system is out of control, take corrective action and repeat all necessary tests until system meets all applicable performance specifications

- Keep necessary parts for routine repairs readily available and immediately repair or replace parts to correct routine or otherwise predictable malfunctions as defined in the startup, shutdown, and malfunction plan

- Develop and implement quality control program including written protocol that describes procedures for calibrations, calibration drift determinations and adjustments, preventative maintenance, data recording/calculations/reporting, accuracy audit procedures, and corrective action program

Several commenters asked how excess emissions and by-passes from NSPS units would be treated. It is true that under section 112 standards, excess emissions determined not to be result of startup, shutdown, or malfunctions may be found to be violations subject to financial penalties. Under the final rule, the EPA has revised the format and eliminated use of the terms "exceedances", "excursions", "excess emissions", and "violations". Under the new format, we have established operational standards for continuous compliance with emission limits and parameter monitoring. For example, the owner or operator must establish a minimum operating temperature for any thermal vapor incinerators used as control devices and must monitor the combustion temperature continuously. Similar performance related parameter values must be established (and monitored) for other control device types and/or processes as specified in the rule. The rule establishes the emission and operating limits but the rule does not specify situations or define the conditions where a "deviation" from the operating standard has occurred. Going outside the established range for the operating parameter or exceeding the emission limit under any circumstance is a deviation, which must be reported to the permitting authority. In addition, the final rule does not establish specific situations where "deviations" from the emission limits or operating requirements are considered "violations" of the rule. In establishing the operating limits, we fully considered the appropriate NSPS definitions of conditions that constitute excess emissions or violation that take into account process and control device fluctuations over time.

We also revised the rule to make the reporting requirements the same for these units to eliminate duplication and added a provision allowing the State permitting authority to consolidate reports to reduce any other duplication. In other words, the same report may be submitted for NSPS and NESHAP reporting purposes, but deviations from the operating standards (formerly referred to as excess emissions) under section 112 determined not to be the result of startup, shutdown, or malfunction events may be assessed as violations that are subject to financial penalties. Emissions from any by-pass for an affected unit (including a unit subject to the NSPS) would be identified in the periodic report required by this rule.

Some commenters (IV-D-30, IV-D-31, IV-D-56) believe if NSPS units are brought under the MACT standard, then the flexibility provided under the MACT rules applies equally to the NSPS units which results in dilution of the NSPS requirements. It is true that we considered allowing NSPS units to select to comply with either the NSPS or MACT standard early in the rule development process, but we rejected this alternative prior to proposal because of the reasons the commenters suggested. An NSPS unit must comply with the specified requirements (summarized above) and is not afforded the flexibility for non-NSPS units.

Commenters IV-D-25 and IV-D-44 believe that the proposed rule does or should exempt FCCU or Claus SRU already subject to and in compliance with the NSPS. These units are affected sources under the MACT rule. If we exempted NSPS units from the MACT rule, we would not know if they are meeting NESHAP requirements. These units are not exempted from MACT requirements in the final rule.

Commenters IV-D-39, IV-D-43, and IV-D-44 believes that non-NSPS units should have the option to comply with NSPS requirements in lieu of the MACT standard requirements so that units in a plant will be subject to the same requirements. We agree with the commenters' suggestions and have added this as an option under the final rule. An affected source that is not subject to the NSPS may choose to comply with the specified NSPS requirements.

Commenters IV-D-47, IV-D-48, and IV-D-53 request that an affected source be able to opt to demonstrate compliance with an NSPS standard to which it becomes subject after the compliance date in lieu of demonstrating compliance with both standards. We can not revise the NSPS requirements in this rulemaking. However, it is likely that a relatively recent performance test conducted to demonstrate compliance with this rule would provide evidence of compliance with the NSPS.

8.2 Definition of Affected Facility vs Definition of Affected Source

Comment: Commenter IV-D-25 urges EPA to make Subpart UUU more clear than the NSPS, particularly in the definitions of affected facility and existing facility.

The rule should include provisions defining whether an existing source can be reconstructed by the addition of a second unit or whether only the added unit becomes a new source. He explains that a refinery can install a new sulfur recovery plant to process H_2S and TRS from the sources controlled by an existing sulfur recovery plant. The NSPS fails to clarify if the addition of the second plant constitutes the addition of a new unit or the modification of an existing unit. If Subpart UUU includes separate standards for new/reconstructed sources, a provision clarifying this situation needs to be added.

Response: The affected sources under Subpart UUU are each existing, newly constructed, or reconstructed FCCU, CRU, and SRU. The only case under the MACT standards where standards differ for existing versus new or reconstructed sources is for inorganic HAP (i.e., HCl) from CRU. Under the example given for sulfur recovery plants, a newly constructed Claus sulfur recovery plant would be subject to the MACT standard for (sulfur) organic HAP and the NSPS for sulfur oxides. The NSPS standards are for the control of criteria pollutants rather than HAP. Under NESHAP, the addition of a second unit triggers the new source standard for the unit because reconstruction entails the replacement of existing components. In the sulfur plant example, the new sulfur plant (whether Claus or other type) would be subject to the MACT limit for organic HAP and the associated monitoring requirements. These standards are the same for new and existing affected sources. We can not modify the NSPS under this rulemaking to make the clarification requested by the commenter. We can, however, clarify the role of a reconstructed affected unit under NESHAP. Under the NESHAP General Provisions "reconstruction" means “the replacement of components of an affected or a previously unaffected stationary source to such an extent that:

- The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source; and
- It is technologically and economically feasible for the reconstructed source to meet the relevant standard(s) established by the Administrator (or a State) pursuant to section 112 of the Act. Upon reconstruction, an affected source, or a stationary source that becomes an affected source, is subject to relevant standards for new sources, including compliance dates, irrespective of any change in emissions of hazardous air pollutants from that source.” It is clear under this definition that a reconstruction is not the addition of a new unit; addition of a new unit is new construction subject to the new source review process.

8.3 Triggering the NSPS due to Emissions from Flares and Combustion Devices

Comment: Commenters IV-D-47, IV-D-48, IV-D-49, IV-D-53, IV-D-54, and IV-D-59 request the rule state that emissions from flares and combustion devices do not trigger NSPS requirements. Commenter IV-D-49 does not agree that compliance with MACT II triggers the applicability of the NSPS based on the definition of "modification" under 40 CFR 60.14. Commenters IV-D-48 and IV-D-54 support the exclusion of streams routed to fuel gas systems and urge EPA to clarify that any stream routed to a fuel gas system does not trigger the NSPS. Commenters IV-D-47 and IV-D-53 believes the rule should be clarified to specifically exclude triggering the NSPS by venting TOC emissions to a flare.

Response: One of the options for the control of TOC emissions from CRU allows venting emissions from the regenerator to a combustion device or a flare that meets the requirements for control devices in §63.11 of the NESHAP General Provisions. The commenter is correct in that the sulfur oxide standards in 40 CFR 60.104 of the NSPS (Subpart J) include a limit for H_2S emissions from fuel gas combustion. CEMS for SO_2 or H_2S are required, as well as associated recordkeeping and reporting requirements. However, it should be pointed out that it is currently common industry practice to vent the CRU emissions to the fuel gas system or flare. As such, the number of units that would significantly increase the amount of fuel gas combusted as a result of this rule is considered to be small. Also, the sulfur content of the vented gases is very low in sulfur concentration; sulfur deactivates the CRU catalyst and is typically removed from the feed stream prior to the CRU. The EPA is reviewing the issue of triggering NSPS requirements as a result of MACT compliance efforts and is considering different solutions which may including revising the NSPS monitoring requirements or issuing a policy directive. It must also be pointed out that applicability to NSPS is a separate determination that is made on a case by case basis and no blanket exclusions are included in the final refinery MACT standards for venting CRU emissions to flares.

8.4 State or Local Requirements

Comment: Commenter IV-D-40 explains that state and local requirements and permit conditions often provide equivalent emission limits that are as stringent or more stringent than the proposed MACT standard. EPA should modify the applicability language to allow a units subject to State/local regulations or permit conditions that are equivalent to or more stringent than the MACT standard to be considered in compliance with the MACT standard and all associated requirements, in the same way provided to NSPS units.

Response: We appreciate the general idea behind the comment (i.e., avoiding duplicative or regulatory overlap and unproductive regulatory requirements); however, determining whether rules are equivalent (or more stringent) is not necessarily that easy. Factors such as test methods, averaging times, format/units are only some of the items to consider in making such a determination. The EPA held several meetings with State regulators in an attempt to identify State requirements that were equivalent to or more stringent than the proposed MACT standard. No such State requirements were identified. Considerable resources would be required to make such determinations on a generic basis on all the regulations covering the units affected by this rule. Equivalency is a case-by-case determination made by the applicable permitting authority.

9.0 IMPACT ANALYSES

9.1 Ni Emission Estimates for CCU Regenerator Vents

Comment: Industry commenters (IV-F-3.1, IV-F-3.2, IV-F-3.3, IV-D-39, and IV-D-40, IV-D-44, IV-D-45, IV-D-47, IV-D-48, 24, IV-D-53) believe EPA has overestimated baseline Ni emissions from CCU. According to the commenters, baseline emissions from 120 CCU are overestimated by an order of magnitude based on the selective use of the average of only two data points. EPA then uses this controlled emission factor to compute the uncontrolled Ni emission factor by dividing it by 95%- the assumed level of control. This ignores the industry-supplied estimates of between 9.6 and 33.5 tpy of Ni based on the mean value of the entire database compared to EPA's estimate of 124 tpy with total baseline HAP of 81 tpy compared to EPA's estimate of 380 tpy. In support, they cite industry-reported data in the 1996 TRI (about 33 tpy of Ni) and EPA's Report to Congress on HAP emissions from the electric utility industry. This report includes estimates of Ni emissions from the generation of electricity using coal, oil, and natural gas. These HAP emissions are at least a factor of 100 below baseline emission estimates. Other commenters point to their low site-specific Ni emission rates. Commenter IV-F-3.3 submits monthly Ni emission data in support. Others believe control of these emissions would be arbitrary and capricious because they are lower than the Ni emissions from the utility industry where EPA determined not to regulate based on the low level of emissions and low risk. Overall, the commenters contend that emissions are de minimus and do not warrant control.

Response: In its initial estimates, the EPA used a mid-range emission factor approach because industry representatives argued that the refineries for which metal HAP emissions data were available were predominantly located in California which has strict fuel standards, had low Ni feed concentrations, and were all well controlled for PM emissions. Therefore, using a direct average or median value of the data that was considered by industry to be biased and not representative of the industry nationwide was inappropriate.

After much corroboration with industry representatives, more detailed data on CCU operations were provided to the Agency. Based on this newly provided information and data, the EPA subsequently has revised the refinery vent impact estimates and emission estimation methodology based on information and data received since proposal. Current estimates of HAP emissions are in general agreement with those made by most petroleum industry representatives. With regard to the comment that refinery Ni emissions are lower than the Ni emissions from the utility industry and that EPA determined not to regulate utilities based on the low level of emissions and low risk, it must be pointed out that this statement does not accurately represent EPA policy relative to Ni emissions from the utilities industry. To date, no formal regulatory determination has been made regarding regulation of any HAP emitted from the utility industry. The EPA is in the process of collecting additional data on metal HAP emissions and will make a determination in the future. Additionally, Ni emission factors for utility boilers burning liquid fuels are not applicable to CCU regenerators as the emission mechanism for PM and metal HAP are different. Use of these utility boiler emission factors is not appropriate for estimating CCU regenerator vent emissions.

9.2 Emission Estimate Methodology

Comment: Commenters IV-D-30 and IV-D-56 disagree with the emission estimate methodology- specifically, the use of lbs per million bbl as the unit for measuring metal HAP emission. This methodology used by EPA does not take into account which one of the three major variables is driving the estimates and can not accurately project emissions in terms of the changing quality of feed to the CCU. The commenter recommends generating emission factors that are unit and feed specific. Using particulate control equipment data available from the API database, EPA may assign appropriate particulate emission values (e.g., 1 lb per Kg coke for an ESP with specific collection area greater than 350 square feet per 1,000 acfm) for each type of particulate control. EPA then should calculate the total metal HAP content on the E-Cat using the equation supplied by the commenter. Feed quality data (concarbon and API gravity) is available from the APR database or can be assumed. The final variable, (1,000 pounds of coke per million barrels) is a function of the heaviness of the feed. EPA should estimate a relationship between coke generation and concarbon (adjusting for other variables such as the mode of unit operation and the type of catalyst used) or choose values for coke generation that are consistent with the concarbon number of the feed (using a linear proportional relationship). This approach allows EPA to evaluate the impact on changes in feed quality on metal HAP emissions at the unit level and industry-wide.

Response: We have developed a more site-specific approach to the impact estimates. However, this analysis does not include a factor for feed quality per se. Consideration of site-specific E-Cat Ni concentration, the most recent approach, is an alternative means of accounting for both feed quality and operational differences on a site-specific basis.

The API database, as provided to EPA, does not contain site specific data on CCU feed quality (e.g., Ni content, concarbon, or API gravity) or control device specific data (such as unit-specific plate area for ESP). These data are considered to be confidential business information by many refiners; and the industry/trade association work group that collected the plant data were unable to share this type of information and data with the EPA in a collective manor.

Based on recent data obtained by EPA regarding Ni E-Cat concentrations, more site specific and unit specific emission estimates have been calculated. These E-Cat based estimates provide an accurate account of current baseline emissions and projected emission reductions. Data regarding trends in Ni content of FCCU feeds is limited and inconclusive. Analysis of feed quality changes is at this time highly speculative given the uncertainty associated with the industry's operational response to the Tier 2 fuel standards. Depending on industry's Tier 2 compliance approach, CCU feed metal HAP content could see a downward trend in spite of increases in crude metal HAP content. To the extent possible, we are coordinating compliance efforts between this rule and the Tier 2 fuel standards.

9.3 Selection of Pollutants in Database

Comment: Commenters IV-D-41 and IV-D-56 disagree with EPA's approach of excluding compounds reported only by one facility that was not verified by any other information. The commenter feels that this procedure may have eliminated data where it was most needed and asks if this excluded data on D/F, cyanide, and Hg where tests have been conducted at only a few units? Also, since emission tests for HAP in the various CRU regeneration cycles are scarce, this procedure may have eliminated any of this data for consideration. Dropping data because other units did not conduct the test is not defensible. If a pollutant is detected in a test, then it should be accepted in the analysis unless there are valid and documented reasons to exclude it. EPA should review its procedures in this regard.

Response: First, the technical information document contains emission factors for D/F, cyanide, and Hg; these data were not excluded from the analysis. To clarify, the methodology used in developing emission factors for the units of concern involved excluding data only in the case where there was a single test that showed the presence of the compound and there were multiple test from the same and other facilities that reported non-detect for the same compound. This methodology regarding treatment of non-detect values was clearly explained in the BID for the proposed rule. The only compounds for which emission factors were not developed and reported based on this criteria are CS_2 and COS from CCU. In the case of POM, these data were treated as a class of HAP and all POM data were considered in developing the reported emission factor even when one specific POM compound was measured at only on facility in a single test.

9.4 Impacts of Additional Pollutants

Comment: Commenters IV-D-30, IV-D-26, IV-D-31, and IV-D-56 ask EPA to add the impacts of decreases in SO_x emissions that would occur with wet scrubbers. In some cases, SO_3 may be considered a HAP. They also request impact analyses of the effect of the standard on D/F and Hg emissions.

Response: We agree with the commenter that SO_x emissions are expected to be reduced when a wet scrubber is used to control CCU PM emissions. Concurrent SO_x emissions reductions have been estimated and are reported in chapter 6 of the BID for the proposed standards.. However, SO_x is not a listed HAP nor is it "considered" a HAP for regulatory purposes. We have not included an analysis of the impact of the standard on D/F and Hg emissions; an impacts analysis was not done because there are no data that indicate that there are appreciable D/F emissions from FCCU or data regarding Hg emissions removal efficiency for FCCU scrubbers.

9.5 Cost Estimates for CCU Catalyst Regenerator Vents

Comment: Commenters IV-F-3.1, IV-F-3.2, IV-D-39, IV-D-40, IV-D-47, IV-D-48, IV-D-49, IV-D-54, and IV-D-59 believe that the capital costs of controls (ESP or scrubber) ranges from about $5 million to $20 million each for each CCU, depending on the unit size and site configuration compared to EPA's estimate of $31 million for the entire industry. According to Commenter IV-D-49, the parameters used in the OAQPS model to estimate the cost of inorganic controls are not representative and are underestimated because EPA did not use site preparation costs (which are significant), the exhaust gas temperature is too low, and the selected control efficiency is not consistent with the required removal efficiency of the unit. EPA has indicated that they would modify the input parameters using a retrofit cost factor of 1.35, an exhaust gas temperature of 500 degrees, a mean particle diameter based on Region V source test data, and an ESP selected control efficiency of 500 ft sq/m-acfm.

Response: The EPA has modified the control cost input parameters using a retrofit cost factor of 1.35, an exhaust gas temperature of 500 degrees, a mean particle diameter based on Region V source test data, and an ESP selected control efficiency of 95%. With the revised inputs, the resulting ESP design (used in the costing) has a specific collection area (SCA) of 500 ftsq/m-acfm, which is consistent with the SCA's for ESP that meet the NSPS PM emission limit as confirmed by industry supplied data.

9.6 Cost Effectiveness Estimates for CCU Catalyst Regenerator Vents

Comment: Commenters IV-F-3.1, IV-F-3.2, IV-F-3.3, IV-D-39, IV-D-40, IV-D-44, IV-D-45, IV-D-47, IV-D-48, IV-D-49, IV-D-53, IV-D-54, and IV-D-59 do not believe that controls for CCU are cost effective. Based on the overestimated emissions and underestimated costs, most commenters believe that the cost effectiveness of the controls for CCU would exceed $1 million dollars per ton of HAP reduced using industry estimates of 38 tpy of total inorganic HAP reduced with annual costs of $48 million or about $200,000 per ton of HAP reduced if controls for organic HAPs are included. Some believe the cost effectiveness for their facility is even higher. According to the commenters, the high cost effectiveness is beyond Congressional intent and not consistent with Administration policy. In support, they cite the Presidential Memorandum of July 16, 1997 to Administrator Browner on implementation of NAAQS which establishes control costs to under $10,000 per ton. According to the commenter, EPA's cost effectiveness (about $97,000 per ton reduced) does not compare well to the policy set by this Administration or to the cost effectiveness for other MACT rulemakings for the petroleum refinery industry (i.e., the HON and Refinery MACT I), which ranges from several hundred thousand dollars to $10,000 per ton reduced. EPA should use its latitude under the CAA to develop a regulation that is not unnecessarily restrictive or costly.

On the other hand, Commenters IV-D-30, IV-D-31, and IV-D-56 disagree with the cost effectiveness as a decision criteria, particularly when estimates are based on a single pollutant because they do not include the substantial reductions in other pollutants or the associated benefits. These ancillary reductions are an important component of aggregate risk reduction and monetary benefits. When these reductions are considered, the cost effectiveness is very low and the rule is beneficial.

Response: As noted in the preceding response, we have revised the costs and emission impacts of the proposed MACT rule based on the information and data received during the comment period. The cost-effectiveness numbers especially for the inorganic (i.e., metal) HAP are high; however, the cost-effectiveness for the entire rule is moderate at about $4,200/ton of pollutants controlled, as is the combined cost-effectiveness for both the refinery MACT standards at about $2,000/ton. These values are comparable to the cost-effectiveness of other rules for the number of sources impacted. And although high, the costs are not considered unreasonable.

With regard to the comments concerning Congressional intent, it must be pointed out that under the CAA Amendments of 1990 passed by Congress the MACT standards are technology based standards and are not to be based on cost-effectiveness. The cost effectiveness values cited by the commenter are applicable to criteria pollutants and not HAP; if one looks at the cost effectiveness of the final rule considering the concurrent reductions in criteria pollutants, then the values are much more reasonable and, as noted above, are in the general range of values mentioned.

We agree that the concurrent and ancillary reductions associated with the control of HAP by the proposed MACT standards are an important component of aggregate risk reduction and monetary benefits and these reductions should be considered in assessing the merits of the rule.

9.7 Low Health Risk Does Not Warrant Proposed Controls

Comment: Commenters IV-F-3.1, IV-F-3.2, IV-D-39, and IV-D-40, IV-D-44, IV-D-45, IV-D-47, IV-D-48, IV-D-49, IV-D-53, IV-D-54, and IV-D-59 cite an industry screening study of 22 CCU that shows low health risk (less than one cancer case in one million) due to Ni emissions. According to these commenters, the low emissions and health risk do not warrant control. Commenters IV-D-30, IV-D-31, and IV-D-33 believe that the emissions and health risk do warrant regulation due to the HAP and the high volume of non-HAP emitted. Commenter IV-D-33 describes the lung cancer rates in communities downwind of the 14 refineries in her area which are 100 percent above expected incidence. According to the commenter, the refineries are a leading source of the PM that contributes to these premature deaths. Commenter IV-D-56 speaks to the numerous SO_2 and H_2S exceedances from particular refineries, the numerous carcinogenic, teratogenic, and mutagenic substances emitted, and the overall concerns in communities exposed to clusters of refineries regarding emissions of persistent bioaccumulative toxic substances and the effect on food chains such as fruit and vegetable gardens.

Response: We have discussed with the industry their screening study of 22 CCU that shows low health risk (less than one cancer case in one million) due to Ni emissions. Preliminary discussion of the industry risk analysis indicated that the facilities examined are considered high emitting sources with high nickel feed; however, upon further inquiry, it appears that all the facilities included in the initial risk assessment study submitted as part of the API comments currently use either an ESP or wet scrubber for control of PM which is the MACT floor technology for CCU. As a result it is difficult to draw any industry wide conclusions on the risk posed by uncontrolled CCU. The final report will be reviewed in detail and will be considered in the risk standard development phase of the NESHAP standard setting process under section 112.

Again, it also must be emphasized that the MACT standards are not risk based but are technology based standards. Risk and cost-effectiveness arguments are appropriate for control options beyond the floor or for the inclusion of area sources neither of which is the case with this source category rulemaking. Risk will be evaluated and considered in the second phase of the NESHAP standard setting process.

9.8 Database Weaknesses

Comment: Commenters IV-D-41, IV-D-31, and IV-D-56 believe the data set on emissions tests was not adequate. Only a few of the nearly 70 pollutants were tested and tests were made on too few units. Test data on CCU came from a set of 8 facilities; no data were available for emission rates at other units and for other pollutants. This is why emission factors had to be extrapolated to other units. Information on particulate emission rates from CCU (the basis for projecting model unit and nationwide emission estimates) also are absent. Data on other variables also were incomplete (e.g., feed quality data and ESP plate areas). Feed quality data is crucial to understanding the relationship between feed quality and HAP metal emissions. The database for CRU was even more limited and pertained only to the coke burn cycle even though there are many different cycles (chloriding cycle, sulfiding step, and purge cycle). EPA should add this information to the BID for the final standards. Some of the emission factor information and additional data are available in the API report. "Characterization of Hazardous Air Pollutant Emissions from FCCU, CRU, and SRU Refinery Process Vents, Final Report, Volumes I-III-Process and HAP Emissions Survey."

Response: EPA is aware of the lack of HAP data and test data; however, the available data in the EPA refinery vent database is adequate to support the analyses conducted as the basis for the proposed standards. We have requested the document/data referenced by the commenter (the report has been added to the project docket) but data referenced by the commenter is not in the version of report as released by the industry. As discussed in comment/response 9.2, much of the process operating data cited by the commenters is considered by some refiners to be confidential business information which made the transfer of data from the industry work group a much more complicated undertaking.

9.9 CRU Catalyst Regenerator Vent Emission Rates

Comment: Commenters IV-D-41 and IV-D-56 state that EPA should review the emission estimates and the suitability of the controls for criteria pollutants for CRU catalyst regenerator vents. According to the commenter, emissions of particulates and SO_x from a large continuous CRU are comparable to those of a CCU.

Response: The commenter did not provide any data to support the comment that particulates and SO_x emissions from a large continuous CRU are comparable to those of a CCU. The data available in the EPA database do not support this contention and a comparison of vent flow rates for continuous CRU regenerators and CCU regenerators makes this assertion very dubious. As mentioned previously, EPA does not have the authority to regulate criteria pollutants under section 112 of the CAA.

9.10 CRU Emissions Table

Comment: Commenters IV-D-41 and IV-D-56 ask EPA to expand the table of emissions from CRU catalyst regenerator vents in the BID for the proposed standards. Since the variety and magnitude of CRU catalyst regenerator vent emissions varies in the different cycles of catalyst regeneration, EPA should specify the cycle to which the data pertain and ensure that emission factors for all cycles are presented.

Response: We have made some basic differentiation of the pollutant types emitted during the various CRU regeneration cycles in the BID for the proposed rule. This effort was limited however by the available data. We did not under take the extensive effort needed to gather additional data on HAP emissions for the CRU regeneration cycles other than the coke-burn cycle, in large part because it was obvious that any additional data collected on emissions during the other cycles would not change the regulatory outcome or level of control required. This is because all units are required to utilize controls under the proposed rule during these CRU catalyst regeneration cycles. It was not necessary to have additional constituent specific emission factors for the other CRU catalyst regeneration cycles to establish the MACT floor or estimate the emission reductions because all units for which site-specific data were gathered during the standard development process were already using the controls required by the proposed rule. And, we have not received any information that any other CRU are doing otherwise. Gathering any additional information and data on this particular point would not be a prudent or cost effective use of the Agency's limited resources.

9.11 Effect of Hydrotreating on Emission Estimates

Comment: Commenters IV-D-41 and IV-D-56 disagree with EPA's conclusion in the BID for the proposed standards that "data were inconclusive as to whether hydrotreating had any effect on the emission factors for HAP metals" and the subsequent decision to use the same emission factors for units that hydrotreat as for those that do not hydrotreat. They argue that a CCU processing hydrotreated feed should emit less metal HAP (and less SO_x and NO_x) per unit throughput than a unit processing non-hydrotreated feed, although both may emit the same amount of Ni per 1,000 pounds of coke burn. This is because the relatively lower Ni content of the hydrotreated feed may be offset by other factors such as relatively higher particulate emissions and higher coke generation rates compared to a unit processing non-hydrotreated feed. Different hydrotreatment units process feeds of different heaviness and the degree of hydrotreatment may vary among units depending on factors such as the mode of operation of the unit and the availability of metal-poisoning resistant catalyst. Rather than partition emission factors according to whether hydrotreating is conducted, EPA should use empirical and material balance equations to link the metal HAP emission factor to the quality of feed and other factors. If the Ni content of the feed is available, then Ni and total metal HAP on the E-Cat may be computed. With the metal content of E-Cat and particulate emission rate, the metal HAP emission rate can be computed as their product. The key to computing metal HAP emissions is information on the quality of feed to the unit.

Response: We agree with the commenter that hydrotreating should result in a metal HAP reduction in the CCU feed. We also agree that some additional attributes of hydrotreating the CCU feed stream may tend to mask or minimize the anticipated metal HAP emission reduction (see discussion in comment/response 1.19). The EPA conducted additional information gathering on hydrotreating following proposal of the rule. Although refinery representatives confirm that the catalyst used in hydrotreatment should effectively adsorb metal HAP and thus reduce the metal HAP content in the CCU feed, there was no general agreement that the metal HAP content of the CCU E-Cat would be reduced (as an industry trend) since this depends on economic as well as process considerations specific to each individual CCU.

As noted previously, the API database, as provided to EPA, does not contain site specific data on CCU feed quality (e.g., Ni content, noncarbon, or API gravity). Based on recent data obtained by EPA regarding Ni E-Cat concentrations, more site specific and unit specific emission estimates have been calculated. These E-Cat based estimates provide an accurate account of current baseline emissions and projected emission reductions. Data regarding FCCU feeds quality changes are among those operating parameters that certain refiners consider to be confidential and are unavailable to EPA at this time.

Using the data available to the Administrator, the EPA could not quantitatively demonstrate that hydrotreating of CCU feed significantly reduced metal HAP emissions from the CCU regenerator vent. Instead, the revised emission approach employs E-Cat Ni concentrations which are more directly linked to Ni emissions (as a surrogate for total metal HAP emissions).

In addition, analysis of CCU feed quality at this time is highly speculative given the uncertainly associated with the industry's operational response to the Tier 2 fuel standards. Depending on industry's Tier 2 compliance approach, FCCU feed's metal HAP content could see a downward trend in spite of increases in crude metal HAP content. To the extent possible, we are coordinating compliance efforts between this rule and the Tier 2 fuel standards.

9.12 Effect of ESP Collection Area on Cost Estimates

Comment: Commenters IV-D-41 and IV-D-56 urge EPA to reestimate the costs for ESPs needed to comply with the standards based on a lower specific collection area. The EPA used a specific collection area of 717 ft^2/1,000 acfm, which seems high especially given the 90% efficiency assumption. EPA should use an efficiency of 98% or higher for effective control of the finer catalyst particles. Industry data indicates that existing units have ESP with specific collection areas ranging from under 100 to about 550 ft^2/1,000 acfm; data provided by API indicate that the PM NSPS is achievable by ESP with specific collection area of about 350 ft^2/1,000 acfm. Cost estimates with an ESP double the required size overestimates the control costs.

Response: Upon further review, it was found that the primary reason for the low removal efficiency while having a high specific collection area was the use of the mean particle size distribution in the design rather than the mean mass particle distribution. The ESP cost estimates were revised to correct this error; see comment/response 9.5.

9.13 Effect of Scrubber Pressure Drop on Costs

Comment: Commenters IV-D-41 and IV-D-56 believe a pressure drop of 10 inches of water is too low for effective control of particulates and SO_x. The Agency should also add the cost of scrubbing the gas flow rate with caustic as an option to control SO_X.

Response: The design pressure drop is dependent on the mean particle size diameter of the PM emissions. Available data regarding particle size distribution for CCU emissions suggests that the particle diameter used in our calculations is reasonable (i.e., 4 μm). The estimated costs for Venturi scrubbers used in the impacts analysis agrees well with design cost estimates provided by a wet scrubber vendor. Alternatively, using 1 μm, the design pressure drop is 25 inches of water, which increases the estimated operating costs by approximately 15 percent.

We did not include the cost of scrubbing with caustic as an SO_2 control option because the rule is intended to control HAP and any additional cost of controlling any criteria pollutants is typically not included in the impacts analysis.

9.14 Effect of CO Monitoring on Compliance Costs for Full Burn CCU

Comment: Commenters IV-D-51 and IV-D-54 believe the compliance costs for complete combustion units are potentially very large and have not been considered in the proposed rule. Some potential compliance methods include: (1) returning unit to partial combustion regeneration and recommission existing CO boiler or build new one if needed, (2) retain complete combustion regeneration but reroute flue gas to a boiler or process heater (existing or new), (3) raise normal stack O_2 by reducing unit feed rate, catalyst circulation rate, and conversion, and raising regen temperature, (4) raise normal stack O_2 by increasing regen blower rate, or (5) raise normal stack O_2 by enriching regen blower air with O_2. Commenter IV-D-53 believes up to 40% of existing non-NSPS complete combustion units would need to consider one of these modifications to comply, with an overall industry wide cost of $130 to 260 million per year.

Response: We agree that some limited number of existing nonNSPS complete combustion units may need to consider one of these modifications to comply with the proposed rule. However, neither the commenter nor the industry has provided any relevant data to fully document the issues or problems associated with complete burn units meeting the 1-hour limit or to substantiate the actual number of CCU that cannot currently comply with the CO 1-hour standard. We do not agree on the likely number of affected units or the cost to the industry that are reported in the comment because the most costly approach was used to make the cost estimates. Based on the limited data provided, one facility was projected in our revised cost estimates to install and use an auxiliary fan to increase the regenerator blower rate by up to 20%.

9.15 Selection of Control Equipment for Costing

Comment: Commenters IV-D-41 and IV-D-56 state that EPA should explain in the BID for the final rule how the control equipment were selected for costing. For example, did EPA use a cost minimization algorithm to decide between different ESP, scrubbers, and other potential control? Also, did EPA cost a combined control device (combining flue gases from multiple CCU or CRU)?

Response: Based on information and data in the EPA/API database which includes a number of sources, ESP and wet scrubbers were used almost exclusively for FCCU control devices. We developed control costs for both ESP and wet scrubbers but the estimates indicated that ESP were always less costly on the basis of PM control, although wet scrubbers are potentially cost competitive if SO_x removal is also required. We did not cost combined flue gas control of multiple CCU. Application of combined stack control are rare in this industry and lead to significant potential challenges in control device maintenance.

9.16 Energy Impacts for Incinerators

Comment: Commenter IV-D-35 asks EPA to revise the estimates for annual natural gas requirements for incinerators. The commenter explains that Beavon Stretford sulfur plants normally do not require incineration of the tail gas due to the low H_2S concentration except during plant upsets. In comparison, typical tail gas plants with amine scrubbing plants (i.e., SCOT) require incineration under California rules if the tail gas H_2S concentration exceeds 10 ppm. Therefore, the requirement for 1.5 billion cubic feet of natural gas annual (pg. 48905 of preamble) for incineration applies to the amine scrubbing plants and not to Beavon-Stretford plants.

Response: According to the EPA database, there are Beavon-Stretford sulfur plants that employ an incinerator. Therefore, these incineration costs were included for the uncontrolled units to allow for a conservative cost projection. The incineration requirement only applies to SRU that have reduced sulfur compound (i.e., COS and CS_2) emissions greater than 500 ppm regardless of the type of tail gas treatment unit employed. It is reasonable to conclude that some of the uncontrolled Beavon Stretford sulfur plant unit will not require incineration but the exact number of these units is not known.

9.17 Additional Environmental Impacts from Bioaccumulative HAP

Comment: Commenter IV-D-56 states that the bioaccumulation potential of reduced sulfur HAP and other air toxics from refineries on fruit trees and vegetable gardens in communities surrounding refineries must be more carefully reviewed by EPA. This commenter describes concerns in affected communities about the health and general pollution impacts from persistent bioaccumulative toxic substances. According to the commenter, refineries, and clusters of refineries in particular, emit numerous carcinogenic, teratogenic and mutagenic substances which need to be comprehensively addressed in the standard.

Response: The MACT standards under section 112 are technology based standards. The second phase of the NESHAP standard setting process involves examining the risk associated with the HAP source categories. The health and general pollution impacts from persistent bioaccumulative toxic substances released from refineries, and clusters of refineries in particular, will be comprehensively addressed in that standard setting effort.

9.18 Economic Analysis

Comment: Commenter IV-D-30 believes the economic impact analysis should include the benefits of non-HAP pollutant reductions.

Response: This rule does not require a benefits analysis for an official regulatory impacts analysis however we have estimated the non-HAP pollutant reductions and have considered the benefits of non-HAP pollutant reductions indirectly in establishing the level of the standard and other associated regulatory requirements.

10.0 ADMINISTRATIVE REQUIREMENTS

10.1 Executive Order 13045 on Children's Health

Comment: Commenter IV-D-56 states that this Executive Order applies to any rule determined to be "economically significant" as defined under Executive Order 12886 and that concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. Due to the large population of children living near refineries in Texas and the other parts of the U.S., Commenter IV-D-56 urges EPA to require more stringent MACT standards in compliance with this order.

Response: Executive Order 13045, "Protection of Children from Environmental Risks and Safety Risks" (April 21, 1997), directs Federal Agencies to include an evaluation of the health or safety effects of planned regulations on children. This Order applies to economically significant rules initiated after April 21, 1998, which concern an environmental risk or safety risk that an Agency has reason to believe may disproportionately affect children. An "economically significant" rule is defined by Executive Order 12866 as any rulemaking that has an annual effect on the economy of $100 million or more, or would adversely affect the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities in a material way. For rules subject to the Executive Order, agencies must explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

These standards are not covered by the Executive Order because the final standards are not economically significant and because EPA is precluded from considering health or safety risks in the development of MACT standards under section 112(d) of the CAA. Section 112(d) requires determination of the minimum level of stringency (i.e., the MACT floor) to be based solely on the performance of technology.

There is no doubt that refineries are major source emitters of HAP and also release high levels of non-HAP criteria/ambient pollutants. The technology-based standards developed under section 112(d) for petroleum refineries greatly reduce these emissions. Implementation of the first stage of air toxic rules for this industry, published in 1995 (60 FR 43244) began in 1998. When fully implemented, this rule will reduce emissions of eleven HAP by 59 percent from current levels and non-HAP VOC by over 60 percent. Today's final rule, which covers process vents from units not subject to the first rule, will reduce metal and organic HAP from these units by 87 percent, with a total emission reduction of HAP and ambient pollutants of well over 100,000 tons per year. In addition, it may be reasonable to expect further emission reductions as the industry increases the use of hydrotreatment in response to the Tier 2 fuel standards.

We have not conducted a risk assessment to estimate the health effects of emissions after the implementation of both sets of standards on either adults or children. We expect to begin work on this type of analysis over the next few year. The results of these studies may lead to additional standards under section 112(f). The residual risk standards under section 112(f) will be risk-based and will consider any disproportionate impact on children's health as required by the Executive Order and EPA policy.

10.2 Executive Order 12898 on Environmental Justice

Comment: Commenter IV-D-56 requests that EPA take into consideration Executive Order 12898 and Title VI of the 1964 Civil Rights Act and implementing regulations applicable since most of the communities where refineries are located in are populated by people of color who are also low-income. Executive Order 12898 prescribes fundamental requirements for federal agencies to insure that all programs and agencies are not allowed to increase the disproportionate burden of environmental hazards in communities of color and low income such as most refinery communities in Texas. According to the commenter, refineries are among the dirtiest industrial operations among the major sources of toxic and hazardous air pollutants and are ranked first among all large industrial and small business sections for citizen air pollution complaints in Texas. Most of these facilities are located in or close to heavily populated areas and are concentrated in clusters. More than 6 million citizens (including more than 3 million people of color or over 51 percent) live in the 14 Texas counties where refineries are located. TRI data show that refineries are high emitters of HAPs that create health problems for those in daycare centers, schools, and nearby homes.

Response: Attention to the impact of environmental pollution on particular segments of our society has been steadily increasing. Concern that minority populations and/or low-income populations bear a disproportionate amount of adverse health and environmental effects led President Clinton to issue Executive Order 12898 (59 FR 7629, February 16, 1994). The EPA's Outreach and Special Project Staff in the Office of Solid Waste and Emergency Response serves to coordinate and implement the Agency's principles and new initiatives, including Environmental Justice. The Agency's Environmental Justice homepage provides a wide range of information on contacts, publications, and resources (see http://es.epa.gov/oeca/main/ej/index.html).

We understand many of the concerns cited by this commenter, but can not resolve them in the context of this rulemaking as the effect of this rule will certainly be to decrease emissions and any associated disproportionate burden on special segments of the population. The proper avenue for investigating this issue lies in the environmental permitting process. The EPA's "Interim Guidance for Investigating Title VI Administrative Complaints Challenging Permits" provides detailed information on the process for filing complaints under Title VI of the Civil Rights Act alleging discriminatory effects resulting from the issuance of pollution control permits by state and local government agencies that receive EPA funding.

10.3 Executive Order 12866

Comment: Commenter IV-D-39 believes the costs of the rule are significant and will exceed $100 million. Because the rulemaking is significant, analysis under Executive Order 12866 is required. Commenters IV-D-30, IV-D-31, and IV-D-56 claim that the full review procedures of Executive Order 12866 apply to this rulemaking if EPA adopts the industry-recommended Ni alternative because this option is likely to "adversely affect in a material way... the environment."

Response: Executive Order 12866 is based on annual costs and not capital costs. The annual costs of this rule are under $60 million and well below the $100 million/yr criterion for a major rule under the Executive Order. In response to the concerns voiced by other commenters, EPA did not adopt the industry-recommended industry alternative and cannot agree with the commenters that the final rule "adversely affects in a material way... the environment."

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11.0 MISCELLANEOUS

11.1 Section 112(j) MACT Hammer

Comment: Commenters IV-F-3.1, IV-D-47, IV-D-49, and IV-D-59 ask EPA to extend the due date for applications for case-by-case MACT applications due to the uncertainties in promulgating this rule before the MACT hammer date of May 15, 1999. The commenters explain that it would be unnecessarily burdensome for industry and permit authorities when a final rule probably will be promulgated shortly after the hammer date if not before. EPA has previously made these extensions for similar reasons. Commenter IV-F-3.2 may ask for a time extension because, in his view, his organization did not have a full 60-day review of the rule because the docket was not complete. However, an extension may jeopardize EPA's ability to promulgate the rule before the hammer date.

Response: This comment has already been resolved. We decided to delay promulgation of this rule until December 1999 when the Tier 2 rule is expected to be finalized to bring the compliance dates under the two rules more closely in line with each other. Details of this change are included in the Federal Register notice (64 FR 26743, 17/05/99). The official source category schedule has been changed to promulgation no later than Nov. 15, 2000 (i.e., the 10-year bin data).

The Office of Mobile Sources has recently finalized the Tier 2 standards that will limit the amount of sulfur in gasoline. Some petroleum refineries may comply with the gasoline sulfur standards by removing both sulfur and metals from the feed to the CCU) and thereby reduce metallic HAP emissions from the CCU regeneration vent. We have moved the Petroleum Refineries--Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plant Units source category to the 10-year bin to gain understanding of the effects of the gasoline sulfur standards on refineries, decide how our final MACT rule should address these effects, and coordinate the implementation and compliance aspects of the MACT rule with the schedule for implementation of the gasoline sulfur program.

11.2 Notification Requirements

Comment: Commenter IV-D-29 recommends that the due date of initial notifications should be specified for area sources that become major sources and for new and reconstructed sources that had an initial startup after the effective date where an application for approval or reconstruction is not required. This is help the source owner/operator and the implementing agency know when a submittal is required.

Response: An area source that subsequently increases its HAP emissions or potential to emit HAP emissions such that the source is a major source becomes subject to all applicable notification requirements in 40 CFR 63.9 of the NESHAP General Provisions. In this case, the notification that an affected source is subject to the relevant standard must be submitted within 120 days after the source becomes subject to the relevant standard. If you have a new or reconstructed source that had an initial startup after the effective date where an application for approval or reconstruction is not required, you must notify the Administrator EPA that the source is subject to the relevant standard within 120 days after startup. In response to the request, we have added these requirements to the table in the final rule summarizing the initial notification requirements.

11.3 Reporting Requirements

Comment: Commenter IV-D-56 believes that EPA should require quarterly reporting for the MACT standards rather than semi-annual reporting. Citizens have a right to know more than twice a year if their local refinery is not complying with the law and want more frequent access to information.

Response: Under the current NESHAP General Provisions, compliance reports are typically submitted semi-annually . Only under certain circumstances are quarterly reports required. Consistent with the General Provisions, this rule requires semi-annual reports of any deviation from the emission limitations (including operating limits) and work practice standards. As part of our efforts to reduce the paperwork burden on States, industry, and the federal government, we are not requiring separate startup, shutdown, and malfunction reports when actions taken to respond to the incident are consistent with the SSMP. If actions taken are not consistent with the plan, detailed information must be included in the next compliance report. Plants also must submit specific information to obtain approval of any planned maintenance activity that could cause a deviation from an emission limitation. The semi-annual reports will provide a comprehensive view of activities and operating problems the facility is experiencing. We believe the information in the semi-annual reports is sufficient to assess the compliance status of a facility and whether an inspection is warranted.

We understand the need for more frequent and up-to-date facility data. EPA is working to resolve this problem by forming the Office of Environmental Information. In the future, we believe this will help you obtain more and better environmental data on the facilities in your area.

11.4 Implementation of Final Rule

Comment: Commenters IV-D-30, IV-D-31, and IV-D-56 recommend that EPA track the various types and numbers of control devices installed in response to the rule and report the information to the public. This would verify the stringency of the standard, confirm the anticipated emission reduction, and reveal the extent to which estimated costs match up with actual expenditures.

Response: We think this is a good idea particularly due to interest in the Tier 2 rule. It also is a good way to review the effectiveness of the standard and emission reduction and actual costs. We will follow-up on this suggestion after the rule is implemented should our resources permit.

11.5 Source-specific Regulatory Approach

Comment: Commenters IV-D-30, IV-D-31, and IV-D-56 advocate a regulatory approach that considered all the pollutants from all media from a source or group of sources. The uncoordinated control of different groups of pollutants from a single source by different regulations developed at different times limits the effectiveness of environmental programs.

Response: We agree with your suggestions as to a more effective regulatory approach. We have learned much from our effort to develop consolidated air and water rules for the pulp and paper industry. We have also taken a broader view on this rulemaking by delaying promulgation to coordinate with the larger Tier 2 effort due to the cross-media impacts. The Agency is using a sector-based approach to environmental protection more and more. In many cases, OAQPS has used and continues to use a sector-based approach in developing MACT standards. In its MACT Partnership Program, OAQPS forms partnerships with industry, trade associations, state agencies, environmental groups, and the general public to provide information and expertise for developing standards.

In general, EPA's current sector-based approach to environmental protection takes a strategic view of problems within the overall regulatory system. This integrated approach allows EPA to deal with issues encountered across a particular industrial or economic group. In using a sector-based approach, EPA works across media, program, and Agency lines to more effectively address the problems inherent and common to each sector. This sector-based approach is flexible; it encompasses regulatory and non-regulatory activities, single media and multimedia considerations, and single and multi-stakeholder involvement. The sector-based approach promotes pollution prevention, discourages cross-media pollution transfers, and eliminates duplication and inconsistencies. Employing a collaborative process within a sector results in better information, better understanding of the problems, identification of innovative solutions, and recognition of sensitive issues, which in turn results in more cost-effective and better environmental results.

11.6 Language Clarification

Comment: Commenter IV-D-49, supported by Commenter IV-D-59, believes EPA needs to add definitions for "process vent," "fuel gas," "boiler," "coke," "thermal incinerator," and "catalytic incinerator;" be consistent when referring to the CCU regenerator vent; clarify the definition of "catalytic cracking unit" and the capacity basis for process heaters and boilers; differentiate between non-fired and fired boilers; and remove the reference to TOC when referring to CCU regenerator vent. Commenter IV-D-53 includes several recommendations for improved clarity in the rule and changes in Appendix A to be more consistent with the MACT I rule for petroleum refineries.

Response: We incorporated many of the commenters' suggestions. The final rule adds new definitions for "process vent", "fuel gas, and "fuel gas system". The new definition of "process vent" is based on the definition used in the MACT I rule modified for the affected sources subject to this rule. We did not include language from the MACT I rule relating to rule exemptions because these exemptions, where applicable, are covered under the applicability section of the rule and need not be repeated in this definition. The new definition of "fuel gas" and “fuel gas system" are directly from MACT I. We clarified the definition of "incinerator" to describe thermal and catalytic types and added the definition of "boiler" to distinguish "fired" vs “non-fired" types, as suggested.

Commenters also suggested changes that make the rule consistent when referring to the CCU catalyst regenerator vent. As discussed in a previous response to comment, Item 1.1, the final rule applies only to process vents on FCCU catalyst regenerators. We revised the proposed definition of "catalytic cracking unit" to be identical to the NSPS which defines "fluid catalytic cracking unit" and "fluid catalytic cracking unit catalyst regenerator". We also corrected the proposed rule to remove the inadvertent reference to TOC.

Reconciling comments on the applicability of the General Provisions was more difficult. There are cases, however, where we disagree with the commenter's recommendations. Our reasons are summarized below.

(1) **Performance test notification requirements under § 63.7(b)**. We do not agree that these notifications should not apply because they are not required under MACT I. The MACT I rule does require performance tests for some process vents, but many of the other types of affected sources (storage tanks, loading racks, wastewater, etc.) have different requirements. The process units regulated under today's final rule have much higher emissions and the tests are more complex — particularly if the plant is complying with the PM or Ni standards for CCU. This notification gives notice to the permitting authority in the case that he/she wants to observe the test.

(2) **Quality assurance program requirements under § 63.7(c).** We do not agree that these requirements should not apply because they are not required under MACT I and not requiring them would reduce recordkeeping/reporting burden. These Q/A requirements are necessary to ensure the validity of performance tests and continuous monitoring data.

(3) **Requirements for operation and maintenance of continuous monitoring systems under § 63.8(c)(6)-(c)(8)**. Many plants now operate COMS and CEMS because of NSPS requirements and State Implementation Plan requirements. Both the proposed rule and the final rule contain requirements for continuous monitoring systems for certain affected sources under the MACT standard and as such, plants containing these sources must demonstrate compliance using data from these systems. These paragraphs establish basic requirements for meeting applicable performance specifications, adjusting the calibration drift, and other efforts that ensure proper operation and maintenance. The requirements are the same as the NSPS. We have tried to make the rule clear in that these requirements are applicable to COMS and CEMS, but not to CPMS. The final rule establishes accuracy and calibration requirements for CPMS. Operation

and maintenance requirements are not included in MACT I because there are no requirements for COMS or CEMS.

(4) **Quality control program requirements under § 63.8(d)**. The results of a quality control program are considered in determining the validity of monitoring data. Like the general provisions, the rule requires a site-specific performance evaluation test plan prior to a performance evaluation conducted for a COMS or CEMS. Like the General Provisions, the rule also requires a written quality control program as part of the notification of compliance status report that describes procedures that will be used for calibrations, drift adjustments, preventative maintenance, data recording, calculations, and reporting, accuracy audit procedures, and corrective action for a malfunctioning monitoring system. The quality control program covers all monitoring systems (whether a COMS, CEMS, or CPMS) and requires a written protocol that describes procedures for calibrations, determination and adjustment of calibration drift, preventative maintenance, data recording/calculations/reporting, and accuracy audit procedures, including sampling and analysis methods. The program for corrective action for a malfunctioning continuous monitoring system can be included in this quality control plan or in the SSMP. We believe these requirements are necessary to ensure the proper operation and maintenance of monitoring systems and are not burdensome. As explained above, the MACT I sources and monitoring requirements differ from this rule and not requiring a quality control plan under MACT I is not relevant to this rule.

For burden reduction purposes, we are not requiring a site specific test plan prior to any performance test required by this rule as described in the quality assurance program requirements in 40 CFR 63.7(c)(2)(i) of the NESHAP General Provisions and we are not requiring a site-specific performance evaluation test plan as described in the quality control program requirements in 40 CFR 63.8(e)(2 through (e)(3). We are requiring that you report the results of the performance test and performance evaluation in the notification of compliance status report and we are requiring that you prepare and implement a written quality control program as described in 40 CFR 63.8(d).

(5) **Requirements for reduction of monitoring data under § 63.8(g)**. This provisions relates to data reduction for continuous emission monitoring systems and continuous opacity monitoring systems which are used by numerous plants in this industry as a result of the NSPS requirements. Separate provisions are included in the rule for the reduction of monitoring data from continuous parameter monitoring systems on a 1-hour or 24-hour averaging period. We added an explanatory note to the entries for 40 CFR 63.8(g)(1) through (g)(4) of Table 44 to clarify the applicability of this provision. The provisions of 40 CFR 63.8(g)(5) apply to all types of monitoring systems at all plants.

(6) **Notification requirements for performance tests under § 63.9(e).** We have retained this notification requirements in the final rule but added an explanatory note to Appendix A. The rule requires notification of the performance test so that EPA can have an observer present if desired. However, a site-specific test plan is not required.

(7) **Notification requirements for opacity and visible emission observations under § 63.9(f).** We have retained this requirement in the final rule because plants using flares as a means of compliance must do a Method 22 test to demonstrate no visible emissions are present. While the final rule also includes opacity standards for plants opting to meet the NSPS requirements and provisions for site-specific opacity standards for fluid catalytic cracking unit catalyst regenerator vents that do not use a wet scrubber as an add-on control device, compliance with these requirements is demonstrated using a COMS rather than Method 9 and the results of these tests are included in the notification of compliance status report along with the results of performance tests. We do not agree that the notification requirement should not be included because it was not included in MACT I because MACT I does not include opacity and visible emission standards. We also do not agree with the commenter's assertions that this requirement should not be included because the provisions of 40 CFR 63.6 (compliance with opacity and VE standards) do not apply. They do apply if VE observations are made. For this reason, the final rule also retains the requirement in § 63.10(d)(3) for reporting the results of opacity or visible emission observations.

(8) **Recordkeeping requirements under §§ 63.10(b)(2)(i)-(b)(2)(xiv) and 63.10(c).** The recordkeeping requirements of this rule summarize these requirements in the NESHAP General Provisions. The MACT I rule does not include requirements for COMS or CEMS or quality control requirements and their recordkeeping requirements differ for this reason and because of the differences in the types of emission sources. The requirements of the General Provisions are not burdensome; they have been approved by OMB. The recordkeeping requirements provide the minimum level of information needed by EPA to determine if compliance is being achieved and maintained.

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16. ABSTRACT

This report provides the background information for the final NESHAP to control hazardous air pollutants (HAP) from catalytic cracking units, catalytic reforming units, and sulfur recovery units at petroleum refineries. This document contains summaries of public comments received on the proposed rule and EPA responses.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
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